IN THE UNITED STATES COURT OF FEDERAL CLAIMS

NORTHSTAR VERMONT YANKEE, LLC, Plaintiff,	)	No. 18-1209C
v.	)	Filed: July 29, 2024
THE UNITED STATES, Defendant.	)	

OPINION AND ORDER

This is the third round of litigation between the parties related to the Department of Energy's ("DOE") breach of its contractual obligation to accept and dispose of spent nuclear fuel ("SNF") from the Vermont Yankee Nuclear Power Station ("VYNPS" or "Vermont Yankee") in Vernon, Vermont. Plaintiff NorthStar Vermont Yankee, LLC claims that it incurred $191,471,150 in damages for the period of January 1, 2014, through December 31, 2018, because of the breach. During this period, VYNPS permanently shut down its operations and loaded all remaining SNF into on-site dry storage.

The Court granted partial summary judgment with respect to $135,892,413 of damages, which was the undisputed portion of the total amount claimed. Approximately $55,578,737 remained in dispute at trial, as well as the Government's claim for an offset based on operations and maintenance ("O&M") cost savings. The disputed damages at issue fall into several categories: (1) Wet Pool Storage Costs Between 2017 and August 2018; (2) Resource Code 490 Allocations; (3) Materials Loader Impairment Adjustments; (4) Tax Payments; (5) Pre-2017 Site Security Costs; (6) Damaged Fuel Container Costs; (7) Camera Maintenance and Inspection Costs; (8) Crane Repair and Maintenance Costs; (9) Crud-Induced-Localized-Corrosion ("CILC")

Channeling Costs; (10) Damaged Fuel Bundle Costs; (11) Spent Fuel Pool Filtration and Demineralizer Costs; (12) Dry Fuel Storage Project Construction Acceleration Costs; and (13) Decommissioning Costs.

The Court held a nine-day trial from October 24, 2022, through November 4, 2022, hearing testimony from 10 fact witnesses and six experts (three experts for each side). The parties completed post-trial briefing on February 8, 2023, and gave closing arguments on February 22, 2023. Upon consideration of the evidence and arguments presented, and for the reasons explained below, the Court finds that Plaintiff is entitled to recover damages for its claimed costs related to wet pool storage, Resource Code 490, materials loader impairment, tax payments attributable to the assessed value of the ISFSIs, damaged fuel containers, camera maintenance and inspection, crane repair and maintenance, the damaged fuel bundle, the accelerated construction payment, and removal of the North Warehouse and John Deere diesel generator less a reduction for removal costs Plaintiff would have incurred during decommissioning. The Court disallows recovery of claimed costs related to tax payments attributable to the assessed value of the spent fuel pool or related to a period beyond 2018, pre-2017 site security, CILC channeling, the temporary spent fuel pool filtration and demineralizer system, removal of the On-Site Storage Installation ("OSSI") building rubble, and the 2016 emergency plan reduction.

BACKGROUND

I. Findings of Fact[1]

Congress enacted the Nuclear Waste Policy Act of 1982 ("NWPA") to address the national problem created by the accumulation of SNF and High-Level Radioactive Waste ("HLW") at

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[1] Other findings of fact pursuant to Rule 52(a) of the Rules of the United States Court of Federal Claims and rulings on mixed questions of fact and law are set forth later in the analysis.

nuclear power plants across the country. *See* 42 U.S.C. § 10101 *et seq.* The Act authorized the Secretary of Energy to contract with nuclear utilities for the disposal of SNF. *Id.* § 10222(a)(1); *see generally Northstar Vt. Yankee, LLC v. United States* (*NSVY*), 159 Fed. Cl. 575, 578–79 (2022); *Entergy Nuclear Vt. Yankee, LLC v. United States* (*ENVY*), 95 Fed. Cl. 160, 169 (2010). Under the statutory scheme, "[t]he utilities would pay fees into a Nuclear Waste Fund that the government would set up under the NWPA. In return, DOE committed to begin accepting and disposing of contract holders' SNF no later than January 31, 1998." *Energy Nw. v. United States*, 641 F.3d 1300, 1302 (Fed. Cir. 2011). Several decisions of this Court and the United States Court of Appeals for the Federal Circuit have extensively chronicled the substantive terms of the Standard Contract, which are identical across all contracts, and the history of the DOE program since 1983, including the Government's breach. *E.g.*, *ENVY*, 95 Fed. Cl. at 168–73; *Pac. Gas & Elec. Co. v. United States* (*Pacific Gas I*), 536 F.3d 1282, 1291 (Fed. Cir. 2008). That background will not be repeated here. For purposes of liability, the salient fact is that "[d]espite its obligation, DOE did not begin accepting spent fuel from the VYNPS by the January 31, 1998 due date," and "[t]o date, DOE has yet to accept any spent fuel from VYNPS or from any other utility." *ENVY*, 95 Fed. Cl. at 171; *see Ind. Mich. Power Co. v. United States*, 422 F.3d 1369, 1374 (Fed. Cir. 2005) (finding DOE's failure constitutes a partial breach of the Standard Contract). The Court focuses its discussion on the Standard Contract terms relevant to Plaintiff's damages claims in this case.

A. Relevant Terms of the Standard Contract

As the Court's partial summary judgment opinion explained, the Standard Contract does not set forth a schedule or rate by which DOE is obligated to accept and dispose of SNF. *NSVY*, 159 Fed. Cl. at 579. Instead, for planning purposes, the contract required DOE to release an annual

capacity report ("ACR") beginning on July 1, 1987, establishing the "projected annual receiving capacity" for the first 10 years "following the projected commencement of operation of the initial DOE facility." Contract for Disposal of SNF and/or HLW at 10 (Art. IV.B.5(b)), JX 1.[2] The Standard Contract also required DOE to issue an annual acceptance priority ranking ("APR") beginning April 1, 1991, creating the order in which it would accept SNF from utilities beginning with the oldest discharged fuel. *Id.* at 10 (Art. IV.B.5(a)).

To schedule a delivery, a utility must submit to DOE a delivery commitment schedule ("DCS") identifying all SNF the utility wants to deliver to DOE beginning 63 months thereafter. *Id.* at 10 (Art. V.B.1). DOE has three months to approve or disapprove the DCS. *Id.* In the event of a disapproval, DOE must advise the utility in writing of "the reasons for such disapproval and request a revised schedule" within 30 days of DOE's notice. *Id.* The parties follow a similar procedure to reach a final delivery schedule, which utilities must submit to DOE at least 12 months prior to the delivery date. *Id.* at 12 (Art. V.C).

If DCSs for SNF require disposal of material beyond DOE's annual capacity, the Standard Contract mandates an acceptance priority based on the age of the discharged fuel. *Id.* at 14–15 (Art. VI.B.1(a)); *see NSVY*, 159 Fed. Cl. at 579 (describing the scheme by its colloquial name, "oldest fuel first" ("OFF")). Notably, a utility is not bound to deliver fuel in the OFF order; rather, the OFF schedule merely establishes a utility's place in the queue. Its allocation could be used "to deliver any fuel that meets the criteria of the Standard Contract." *NSVY*, 159 Fed. Cl. at 579 n.4;

[2] For ease of reference, joint exhibits are denoted as "JX," Plaintiff's exhibits are denoted as "PX," and the Government's exhibits are denoted as "DX." Any citations to demonstrative exhibits are denoted as "PDX" and "DDX" for Plaintiff and the Government, respectively. Citations to the trial transcript refer to witness and page as "Name, Tr. at __."

see JX 1 at 12 (Art. V.E). The contract also contains a provision allowing utilities, with DOE's approval, to exchange approved DCSs. JX 1 at 12–13 (Art. V.E).

Whether under OFF or through exchanges, DOE has a clear and unambiguous obligation under the contract to dispose of both standard and other than standard fuel. *NSVY*, 159 Fed. Cl. at 586–87. Standard fuel is fuel that meets all the general specifications set forth in Appendix E of the Standard Contract, including the criteria that the fuel is cooled a minimum of five years. *Id.* at 587; *see* JX 1 at 42, 43. Other than standard fuel consists of failed fuel and, as relevant here, nonstandard fuel, which includes Nonstandard Fuel--Class NS-3, also referred to as "short-cooled fuel." *NSVY*, 159 Fed. Cl. at 587; JX 1 at 42. Although the requirement to accept both categories of fuel is the same, unlike standard fuel, the Standard Contract qualifies DOE's obligation with respect to other than standard fuel. *NSVY*, 159 Fed. Cl. at 587. "Specifically, it requires a utility to obtain delivery and procedure confirmation from DOE prior to delivery of other than standard fuel" and, within 60 days of receiving a confirmation request, requires DOE "to advise the utility as to the technical feasibility of disposing of such fuel on the currently agreed to schedule and any schedule adjustment for such services." *Id.* (internal quotation marks omitted); *see* JX 1 at 14 (Art. VI.A.2(b)). "Absent the need for an adjustment, the contract language contemplates the disposal of other than standard fuel on the currently agreed to schedule." *NSVY*, 159 Fed. Cl. at 588 (internal quotation marks omitted).

Pursuant to the contract, DOE issued an ACR in 1987 ("1987 ACR") outlining DOE's projected receiving capacity and annual acceptance ranking of SNF for the first 10 years of the program. *See generally* 1987 ACR, JX 2. That report also referred to DOE's 1987 Mission Plan Amendment, which identified DOE's projected waste acceptance rates through 2038. *Id.* at 7; 1987 Mission Plan Amendment at 60–61, DX 3025 (1,200 Metric Tons of Uranium

("MTUs")/Year for 1998–2002; 2,000 MTUs/year for 2003; 2,650 MTUs/year for 2004–2007; and 3,000 MTUs/year thereafter). In *Pacific Gas I*, the Federal Circuit held that the 1987 ACR process was the "most accurate picture of the parties' intent" before DOE's breach and, as such, "provides the mechanism for calculating the acceptance rate under the contract." 536 F.3d at 1290; *see id.* at 1292 ("[T]he Standard Contract required DOE to accept SNF/HLW in accordance with the 1987 ACR process."); *see also Portland Gen. Elec. Co. v. United States*, 107 Fed. Cl. 633, 638 n.1 (2012). Despite Plaintiff's compliance with the Standard Contract, DOE has yet to pick up any fuel from Vermont Yankee, requiring Plaintiff to pursue mitigation efforts.

B. Plaintiff's Mitigation Efforts at Vermont Yankee

Vermont Yankee is a single unit boiling water reactor that began commercial operations in 1972. Swanger, Tr. at 45:7–9, 46:3–5; Joint Stipulations ¶ 3, ECF No. 81. While in operation, the plant stored SNF in underwater racks in a spent fuel pool both to cool the fuel assemblies and protect against radiation.[3] Swanger, Tr. at 58:24–59:3. As a precaution, operating plants like Vermont Yankee generally maintain sufficient room in their pools to offload all the fuel assemblies in the reactor core, a margin known a "full core reserve." *Id.* at 51:10–17; *see ENVY*, 95 Fed. Cl. at 172. If an operating plant approaches full core reserve, and can no longer offload assemblies into its pool, the options—absent DOE accepting the fuel and transporting it offsite—are to halt operations or build and maintain dry fuel storage. *See* Swanger, Tr. at 51:22–52:2. At Vermont Yankee, full core reserve consisted of 368 assemblies. *Id.* at 51:10–17. Due to the Government's continuing breach, Plaintiff had to increase its spent fuel storage capacity at the site.

[3] Details of nuclear operations at VYNPS, *i.e.*, its production of electricity, composition of its fuel assemblies, cycling of fuel, etc., are well documented in prior opinions. *See, e.g.*, *ENVY*, 95 Fed. Cl. at 168–69.

By 2008, Vermont Yankee built its first Independent Spent Fuel Storage ("ISFSI") pad ("Pad 1") in the northwest corner of the site's Protected Area[4] to address the plant's storage needs. *Id.* at 53:24–54:2. ISFSI Pad 1 could hold up to 40 casks; however, only 36 casks could be safely accommodated to ensure enough room to shuffle casks around, if necessary, until a second ISFSI pad was built. *Id.* at 84:2–11; ECF No. 81 ¶ 7. For its dry storage cask system, Plaintiff employed a Holtec multi-purpose canister ("MPC"), namely the Holtec HI-STORM 100S Overpack ("HI-STORM" or "overpack"), which holds 68 spent fuel assemblies and weighs about 180 tons. Swanger, Tr. at 54:16–55:24, 55:25–56:1, 85:2–9; ECF No. 81 ¶ 7.

In Round 1, which covered the period prior to April 30, 2008, Plaintiff recovered $40,739,217 in damages (plus $46,545.47 in statutory costs) associated with the construction of Pad 1, the purchase of five Holtec dry storage systems, and related costs for transfer and loading.[5] Pl.'s Post-Trial Br. at 13, ECF No. 102 (citing *ENVY*, 95 Fed. Cl. at 175); *see* Rule 58 J., *Entergy Nuclear Vt. Yankee, LLC v. United States*, No. 03-2663C (Fed. Cl. Mar. 18, 2013), ECF No. 209. In Round 2, which covered the period of May 1, 2008, through December 31, 2013, Plaintiff recovered $19,144,174 in stipulated damages related to its purchase of eight additional MPCs and eight overpacks, as well as other associated loading and transfer costs. ECF No. 102 at 13; *see* Rule 58 J., *Entergy Nuclear Vt. Yankee, LLC v. United States*, No. 14-343C (Fed. Cl. May 6, 2016), ECF No. 30. By June 2012, Plaintiff had loaded 13 MPCs onto Pad 1. ECF No. 81 ¶ 8.

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[4] The area housing spent nuclear fuel is to be protected by additional security and is known as the "protected area." Swanger, Tr. at 54:4–8; *see* Ryan, Tr. at 678:3–679:1.

[5] In the prior rounds of litigation, Plaintiff was identified as Entergy Nuclear Vermont Yankee, LLC. Pursuant to a transaction that closed on January 11, 2019, the ownership and name of Plaintiff, as well as the holder of the Standard Contract, changed to NorthStar Vermont Yankee, LLC. Pl.'s Initial Disclosures at 1 n.1, PX 3199; ECF No. 81 ¶ 1.

On August 27, 2013, Plaintiff announced the permanent shutdown of VYNPS, and the plant ceased power generating operations by December 2014. Swanger, Tr. at 44:12–15, 75:1–2; ECF No. 81 ¶ 4. Given DOE's ongoing failure to pick up SNF, Vermont Yankee required a second ISFSI pad ("Pad 2") to permit the transfer of all remaining fuel from the wet pool to dry cask storage. Swanger, Tr. at 82:4–84:11, 94:1–10; ECF No. 81 ¶ 4. Under Vermont Law, Plaintiff had to obtain a Certificate of Public Good ("CPG") from the Vermont Public Utility Commission ("PUC") prior to building an ISFSI. Thomas, Tr. at 474:24–475:12. In December 2014, Plaintiff applied for a second CPG from the PUC to construct Pad 2, which the PUC issued in June 2016. ECF No. 81 ¶ 9.

At that time, Plaintiff planned to complete the construction of Pad 2 by November 2017 and load all SNF into casks for dry storage by June 2020. Swanger, Tr. at 85:15–17. However, in June 2016, Holtec submitted to the Nuclear Regulatory Commission ("NRC") a license amendment for its existing Holtec Certificate of Compliance ("COC"),[6] requesting approval to lower the five-year cooling limitation for the cask system used at Vermont Yankee down to two years. *Id.* at 85:18–86:10, 87:17–24.

Anticipating NRC approval of the Holtec HI-STORM COC amendment, Plaintiff accelerated its plan to load all SNF to dry storage to September 2018, considering the significant financial savings and operational benefits from the earlier transfer of fuel to dry storage. *Id.* at 88:1–89:9, 90:1–10, 92:1–2. To accomplish this, Plaintiff paid Holtec $1 million to accelerate the completion of Pad 2 to September 1, 2017, which allowed it to employ the same construction crew

[6] Under the NWPA, the NRC is responsible for certifying the design of packages (*i.e.*, the shipping container or packaging and its contents) for the transportation of SNF. Easton, Tr. at 173:10–13, 199:21–25; *see id.* at 197:14–198:16 (explaining that the NRC reviews package fabrication, shipping and cask designs, and operating procedures for handling and use of the package and issues COCs indicating NRC approval).

on multiple projects and save monthly O&M costs (approximately $1.2 million/month). *Id.* at 94:11–96:1; Holtec Blanket Release at 1, PX 3155. Plaintiff sought an exemption from the NRC to proceed with its efforts while the Holtec license amendment was pending. Swanger, Tr. at 87:20–24; Entergy Exemption Req. at -5885–5886, PX 3172. The NRC granted the exemption in February 2018. Swanger, Tr. at 91:21–23. Plaintiff also sought and received an amendment to the CPG in August 2017, permitting Plaintiff to relocate its security fence around the ISFSI and make other modifications to reduce the size of the Protected Area. ECF No. 81 ¶ 9. Between June 2017 and August 1, 2018, Plaintiff loaded all remaining SNF (45 MPCs) to the ISFSI. Swanger, Tr. at 84:15–20, 96:7–9; ECF No. 81 ¶ 11.

DISCUSSION

I. Legal Standards for Decision

Plaintiff is claiming damages for expenses it incurred to mitigate DOE's partial breach of the Standard Contract from January 1, 2014, through December 31, 2018. The remedy for breach of contract, whether partial or otherwise, is "damages sufficient to place the injured party in as good a position as it would have been had the breaching party fully performed." *Portland Gen.*, 107 Fed. Cl. at 641 (quoting *Ind. Mich.*, 422 F.3d. at 1373). To recover damages, Plaintiff must establish by a preponderance of evidence that: "(1) the damages were reasonably foreseeable by the breaching party at the time of contracting; (2) the breach is a substantial causal factor in the damages; and (3) the damages are shown with reasonable certainty." *Ind. Mich.*, 422 F.3d. at 1373 (citing *Energy Cap. Corp. v. United States*, 302 F.3d 1314, 1320 (Fed. Cir. 2002)).

A. Foreseeability

Damages are considered foreseeable when they "follow[] from the breach (a) in the ordinary course of events, or (b) as a result of special circumstances, beyond the ordinary course

of events, that the party in breach had reason to know." RESTATEMENT (SECOND) OF CONTRACTS § 351(2) (1981). This principle safeguards a breaching party from liability for "damages that 'it did not at the time of contracting have reason to foresee as a probable result of such a breach.'" *Citizens Fed. Bank v. United States*, 474 F.3d 1314, 1321 (Fed. Cir. 2007) (quoting RESTATEMENT (SECOND) OF CONTRACTS § 351 cmt. a). "Foreseeability is determined at the time the contract was executed," and the "non-breaching party must demonstrate that both the magnitude and type of damages or injury were foreseeable at the time of contract formation." *Portland Gen.*, 107 Fed. Cl. at 641; *see also Ind. Mich.*, 422 F.3d at 1373; *Landmark Land Co. v. FDIC*, 256 F.3d 1365, 1378 (Fed. Cir. 2001)).

Plaintiff need not demonstrate that a particular means of responding to the breach was foreseeable. *Id.* "What is required is merely that the injury actually suffered must be one of a kind that the defendant had reason to foresee and of an amount that is not beyond the bounds of reasonable prediction." *Citizens Fed.*, 474 F.3d at 1321 (quoting Joseph M. Perillo, 11 Corbin on Contracts § 56.7 at 108 (2005 rev. ed.)); *see S. Nuclear Operating Co. v. United States*, 77 Fed. Cl. 396, 405 (2007) ("While the general response to a breach must be foreseen, the particular way that a mitigating decision is implemented need not."). In other words, the foreseeability prong "applies to the type of loss, not to the means of mitigation." *Sacramento Mun. Util. Dist. v. United States* (*SMUD I*), 293 F. App'x 766, 771 (Fed. Cir. 2008) (citing *Citizens Fed.*, 474 F.3d at 1321). As the Federal Circuit and this Court have consistently held, it was foreseeable that DOE's non-performance under the Standard Contract would result in utilities incurring costs related to storage of SNF. *See, e.g.*, *Ind. Mich.*, 422 F.3d at 1376; *Duke Energy Progress, Inc. v. United States*, 135 Fed. Cl. 279, 287 (2017); *Sys. Fuels, Inc. v. United States*, 79 Fed. Cl. 37, 59 (2007).

B. Causation

Plaintiff must also prove that DOE's breach caused each of the claimed costs. Causation, like foreseeability, is a question of fact. *Bluebonnet Sav. Bank, F.S.B. v. United States*, 266 F.3d 1348, 1356 (Fed. Cir. 2001). There are two standards employed by this Court for determining causation—the "but for" test and the "substantial factor" test. *Portland Gen.*, 107 Fed. Cl. at 641. Under the but-for test, the breaching party is liable for those damages that it directly and entirely caused. *Id.* at 641–42. Plaintiff "bears the burden of showing that but for the breach, the purported damages would not have occurred by 'submit[ting] a hypothetical model establishing what its costs would have been in the absence of breach.'" *Duke Energy*, 135 Fed. Cl. at 287 (alteration in original) (quoting *Vt. Yankee Nuclear Power Corp. v. Entergy Nuclear Vt. Yankee, LLC*, 683 F.3d 1330, 1350 (Fed. Cir. 2012)).

"Causation must be 'definitely established,' but the breach need not be the sole cause of the damages." *Duke Energy*, 135 Fed. Cl. at 287 (quoting *Cal. Fed. Bank v. United States*, 395 F.3d 1263, 1267–68 (Fed. Cir. 2005)). "The existence of other factors operating in confluence with the breach will not necessarily preclude recovery based on the breach." *Portland Gen.*, 107 Fed. Cl. at 642 (quoting *Cal. Fed. Bank*, 395 F.3d at 1268). Under the substantial-factor test, the breaching party is "liable if the breach was a substantial causal factor of the damages." *Id.* (citing *Ind. Mich.*, 422 F.3d at 1373).

The Court has the discretion to apply the appropriate causation standard, *Citizens Fed.*, 474 F.3d at 1318, but the Federal Circuit has stated that "the substantial factor test is not preferred," *Yankee Atomic Elec. Co. v. United States*, 536 F.3d 1268, 1272 (Fed. Cir. 2008). Accordingly, the Court will apply the "but for" test.

C. Reasonable Certainty

Finally, Plaintiff must prove its claimed damages with reasonable certainty. *Ind. Mich.*, 422 F.3d at 1373. A fair and reasonable approximation of damages is sufficient. *See, e.g.*, *Energy Cap.*, 302 F.3d at 1329; *Hughes Commc'ns Galaxy, Inc. v. United States*, 271 F.3d 1060, 1067–68 (Fed. Cir. 2001). "Absolute certainty is not required . . . because 'the risk of uncertainty must fall on the defendant whose wrongful conduct caused the damages.'" *Dominion Res., Inc. v. United States*, 84 Fed. Cl. 259, 270 (2008) (quoting *Energy Cap.*, 302 F.3d at 1327), *aff'd*, 641 F.3d 1359 (Fed. Cir. 2011). "If 'a reasonable probability of damages can be clearly established, uncertainty as to the amount will not preclude recovery.'" *Id.* (quoting *Glendale Fed. Bank, F.S.B. v. United States*, 378 F.3d 1308, 1313 (Fed. Cir. 2004)); *see Ind. Mich.*, 422 F.3d at 1373 (explaining that the amount of damages need not be "'ascertainable with absolute exactness or mathematical precision'" (quoting *San Carlos Irrigation & Drainage Dist. v. United States*, 111 F.3d 1557, 1563 (Fed. Cir. 1997))). However, "recovery for speculative damages is precluded." *Ind. Mich.*, 422 F.3d at 1373. To assess certainty, "the court may 'act upon probable and inferential as well as direct and positive proof.'" *Dominion Res.*, 84 Fed. Cl. at 270 (quoting *Locke v. United States*, 283 F.2d 521, 524 (Ct. Cl. 1960)).

D. The Government's Burden of Proof

After Plaintiff meets its three-part burden of foreseeability, causation, and reasonable certainty, the Government may seek reductions in claimed damages by demonstrating that Plaintiff's mitigation efforts were unreasonable. *Duke Energy*, 135 Fed. Cl. at 287 (citing *Tenn. Valley Auth. v. United States*, 69 Fed. Cl. 515, 523 (2006)). Mitigation damages are intended to "reimburse a non-breaching party to a contract for the expense it incurred in attempting to rectify the injury the breach caused it." *Id.* at 286 (quoting *Citizens Fed.*, 474 F.3d at 1320). The

breaching party bears the burden to establish that the plaintiff's damages should be reduced or denied. *Id.* (citing *Home Sav. of America, F.S.B. v. United States*, 399 F.3d 1341, 1353 (Fed. Cir. 2005)). Plaintiff's damages may be reduced to the extent that the Government can show Plaintiff did not undertake reasonable efforts to mitigate its damages or that the efforts it did undertake were inappropriate or unreasonable. *Sys. Fuel*s, 79 Fed. Cl. at 52.

The Government may also "seek to offset a damages award due to avoided costs (i.e., non-breach-world costs that the plaintiff avoided because of the breach)." *Energy Nw.*, 641 F.3d at 1308 n.5. In such case, the Government bears the burden of "pointing out the costs it believes the plaintiff avoided because of its breach." *S. Nuclear Operating Co. v. United States*, 637 F.3d 1297, 1304 (Fed. Cir. 2011). Once it has articulated a proper offset, the "burden shift[s] to the plaintiff to incorporate those saved costs into its formulation of a plausible but-for world." *Id.*

II. Wet Pool Storage Costs Between 2017 and August 2018 Are Recoverable.

The first category of damages regarding wet pool storage costs raises the key question of whether Plaintiff's "exchanges" model of recovery (the "Graves model"), developed by its expert, Mr. Frank Graves,[7] establishes that DOE would have removed all SNF from Vermont Yankee by no later than the end of 2016. The Graves model is not new to the world of SNF litigation; however, this case presents the novel question of whether the Government would have accepted short-cooled fuel—meaning fuel cooled less than five years—on the timeline modeled by Mr. Graves. Based on the evidence adduced at trial, the Court concludes that more likely than not a robust exchanges market would have developed amongst the utilities and that it was technically

[7] Mr. Graves was qualified as an expert in "energy industry economics, electric utility practices, markets and modeling, the establishment and operation of a market for exchanges of DOE spent fuel acceptance [allocations] had DOE performed, and . . . the impacts of such a market . . . on the Vermont Yankee circumstances in a but for world of DOE performance." Graves, Tr. at 890:12–19, 891:6–8.

feasible for DOE to have accepted and disposed of NSVY's minimal amounts of short-cooled fuel on the schedule offered by Plaintiff. Moreover, the Court finds the Government's alternative exchanges model (the "Gurrea model") developed by its expert, Dr. Stuart Gurrea,[8] to be unreliable given its underlying assumptions and other defects.

A. A Robust Exchanges Market Would Have Developed in the Non-Breach World.

Plaintiff demonstrated by preponderant evidence that an exchanges market for DOE acceptance allocations would have developed in the non-breach world, given the cooperative nature of the nuclear industry and the efficiencies (for both DOE and nuclear power plants) that would result from utilities participating in exchanges as opposed to relying on DOE fuel pickups on the OFF schedule alone. The Standard Contract expressly contemplates "exchange" rights because the utilities requested these rights during the comment period to ensure flexibility in managing their spent fuel inventory. Barton, Tr. at 1349:11–16; DOE Action Memo. (Apr. 8, 1983) at -0899, PX 3003; Standard Contract for Disposal of SNF and/or HLW, 48 Fed. Reg. 16,590–01, 16,592 (Apr. 18, 1983). The Exchanges clause provides:

> Purchaser shall have the right to determine which SNF and/or HLW is delivered to DOE, *provided, however*, that Purchaser shall comply with the requirements of this contract. Purchaser shall have the right to exchange approved delivery commitment schedules with parties to other contracts with DOE for disposal of SNF and/or HLW; *provided, however*, that DOE shall, in advance, have the right to approve or disapprove, in its sole discretion, any such exchanges. Not less than six (6) months prior to the delivery date specified in the Purchaser's approved delivery commitment schedule, the Purchaser shall submit to DOE an exchange request, which states the priority ranking of both the Purchaser hereunder and any other Purchaser with whom the exchange of approved delivery commitment schedules is proposed. DOE shall approve or disapprove the proposed exchange within thirty (30) days after receipt. In the event of disapproval, DOE shall advise the Purchaser in writing of the reasons for such disapproval.

[8] Dr. Gurrea was qualified as an expert "in the field of economics and economic modeling." Gurrea, Tr. at 1750:2–4, 15.

JX 1 at 12–13 (Art. V.E) (emphases in original).

Exchanges are a more efficient way to manage the removal of spent fuel needs across the industry than removal based on OFF priority because it allows utilities to avoid or minimize the high costs associated with fuel storage, *e.g.*, building dry storage (approximately $40 million), managing an ISFSI (approximately $300,000 to maintain and $2 million per cask added), or monitoring a wet pool for a shutdown reactor (approximately $10 million). Graves, Tr. at 940:6–10, 941:4–17, 984:3–7 ("[E]xchanges are an opportunity to improve on the OFF schedule[.]"), 1012:23–24 ("OFF is a floor on how good you could do."). It also allows utilities to coordinate cask loading campaigns at their plants, reducing per-cask loading expenses by permitting the utilities to schedule fewer, larger shipments using exchanges rather than the potentially smaller, incremental shipments determined by the OFF schedule. *See* Swanger, Tr. at 64:12–65:10; Graves, Tr. at 909:6–910:9. Such efficiencies could similarly benefit DOE in fulfilling its acceptance and transportation obligations. *See* Barton, Tr. at 1340:23–1341:1.

DOE expressly encouraged utilities to solve their fuel removal needs using the Exchanges provision. *E.g.*, Letter from Lake Barrett, DOE, to David Amerine, Ne. Util. Serv. Co. (June 14, 1999) at -002484, PX 3061 ("The Department encourages Northeast Utilities to pursue [the Exchanges provision] once a repository becomes operational."); Zabransky Dep. Tr. at 2731:15–19, PX 3276; Barton, Tr. at 1345:18–25. It even took steps in the mid-1990s to develop an electronic bulletin board to facilitate exchanges. *E.g.*, Graves, Tr. at 948:4–18; Barton, Tr. at 1351:2–10; TRW Env't Safety Sys., Task Mgmt. Plan: Development of a DCS Exchange Network (Jan. 20, 1994) at -0119, PX 3044 ("DOE has determined that an electronic bulletin board system (BBS), capable of providing up to date information on the status of approved DCSs needs to be developed and available to Purchasers as soon as possible."). And several witnesses testified at

trial as to the general cooperative nature of the nuclear utility industry, which supports the conclusion that exchanges would be an accepted alternative to OFF. *See* Swanger, Tr. at 65:15–69:20; Graves, Tr. at 905:13–22, 906:15–907:24.

A litany of prior SNF cases have agreed that the use of exchanges in the non-breach world was more likely than not and have recognized prior versions of the Graves model as reliable. *See, e.g.*, *Sacramento Mun. Util. Dist. v. United States* (*SMUD II*), 566 F. App'x 985, 990, 994 (Fed. Cir. 2014) (noting that utilities historically have engaged in mutually beneficial exchanges, that exchanges were foreseeable in view of the Exchanges clause, and that DOE stood to benefit from cost-saving exchanges); *Yankee Atomic Elec. Co. v. United States*, 679 F.3d 1354, 1359–60 (Fed. Cir. 2012); *Pac. Gas & Elec. Co. v. United States* (*Pacific Gas III*), 668 F.3d 1346, 1354 (Fed. Cir. 2012); *Dairyland Power Co-op. v. United States* (*Dairyland II*), 645 F.3d 1363, 1370 (Fed. Cir. 2011) (finding no clear error in the trial court's adopting the Graves exchanges model as reliable and not too speculative); *see also Portland Gen.*, 107 Fed. Cl. at 645. Moreover, for the first time in the history of SNF cases, the Government in this case submitted its own exchanges model—the Gurrea model—because the Government agrees that some form of an exchanges market would have developed. It is therefore undisputed that exchanges would have occurred. *See* Barton, Tr. at 1343:11–14 (agreeing that she "would expect that there would be some level of exchanges," if and when DOE performs)

The Court further finds that as of the claim period at issue in this case (2014–2018) the market of exchanges in the non-breach world would have been robust and mature. By 2014, the DOE waste management program would have been operating for 16 years, meaning there would have been a functioning exchanges market since at least 1998, if not earlier, considering that utilities had to submit DCSs at least 63 months (between 1992–1993) ahead of the initial 1998

pick-up date. *See* JX 1 at 11 (Art. V.B); PX 3044 at -0119; *see also Dairyland Power Co-op. v. United States* (*Dairyland I*), 90 Fed. Cl. 615, 632 (2009) ("In the non-breach world, Dairyland would have had plenty of time to pursue and to reach agreement on exchanges with utilities that would have been scheduled for 1998 SNF acceptance in the OFF queue."). Given the cooperative nature of the nuclear utility industry and the incentives of all parties to the Standard Contract for streamlining acceptance and avoiding storage costs, a mature market would have developed after over 16 years of program operation. As support, the Court credits testimony by Mr. Graves that, while the program may have been constrained between 1998 and 2004, the problem would disappear by 2004 because DOE's capacity would begin exceeding the utilities' pickup needs, creating "slack" in the program and the exchanges market. Graves, Tr. at 911:1–25, 972:19–973:23. This is consistent with findings in prior SNF cases concerning the growth of the exchanges market in the non-breach world. *See, e.g.*, *Portland Gen.*, 107 Fed. Cl. at 653 (finding that the exchanges market would have matured by 2002 after four years of program operation and utilities would have participated prior to 2005 when the cost of exchanges dropped due to then-current supply exceeding demand). Moreover, the Court credits Mr. Swanger's testimony that Plaintiff would have been willing to participate in the exchanges market to remove SNF at the Vermont Yankee site. Swanger, Tr. at 63:24–65:14.

Accordingly, the Court concludes that utilities, including VYNPS, more likely than not would have participated in exchanges and that a robust exchanges market would have developed by 2014.

B. DOE Would Have Accepted Short-Cooled Fuel on the Timeline Outlined in the Graves Model.

The next issue—whether DOE would have accepted NSVY's short-cooled fuel—is a question of first impression. The Court has already determined that, as a matter of law, DOE was

obligated to dispose of short-cooled fuel on the same schedule as standard fuel, unless technical feasibility concerns necessitated a schedule adjustment. Based on the evidence presented at trial, the Court finds that it would have been more likely than not technically feasible for DOE to accept short-cooled fuel on the schedule Plaintiff outlines and that the Graves model reliably shows that all SNF at VYNPS would have been removed by the end of 2016.

1. The Standard Contract Requires DOE to Accept Short-Cooled Fuel.

As discussed above, in its prior ruling on partial summary judgment, the Court held that the plain language of the Standard Contract requires DOE to accept short-cooled fuel on the same delivery schedule as standard fuel, *unless* it is technically infeasible to accept and dispose of the fuel on that schedule, in which case DOE must advise the utility of any schedule adjustment for such service. *NSVY*, 159 Fed. Cl. at 587–88.

Significantly, "the Standard Contract draws no distinctions in the treatment of the various subclassifications of other than standard fuel," including nonstandard fuel (such as short-cooled fuel) versus failed fuel. *Id*. at 588. Other judges of this court have expressly found that the exchanges market could accommodate failed fuel where there were no technical feasibility concerns, and that DOE may not indefinitely defer or postpone its disposal obligation for such fuel. *See Portland Gen.*, 107 Fed. Cl. at 651 (noting that the plaintiff was able to handle failed fuel without any special accommodation and that "there is no reason to think that the storage and shipment of failed fuel will present a problem that renders the exchange market inadequate for [the plaintiff] and other utilities' needs"); *Yankee Atomic Elec. Co. v. United States*, 73 Fed. Cl. 249, 310–12 (2006) (holding that the relevant provision "may not be fairly construed to indefinitely defer or postpone disposal" of failed fuel), *aff'd in part, rev'd in part and remanded*, 536 F.3d 1268 (Fed. Cir. 2008). The same reasoning is true for short-cooled fuel, barring valid technical

feasibility concerns. *Cf. S. Cal. Edison Co. v. United States*, 93 Fed. Cl. 337, 370 (2010) (finding that, other than proper licensing, disposal of failed fuel would not require extraordinary measures, and thus DOE would have accepted failed fuel on the same timeline as standard fuel), *aff'd*, 655 F.3d 1319 (Fed. Cir. 2011); *Dairyland Power I*, 90 Fed. Cl. at 633, 636 (finding that it was technically feasible for DOE to pick up failed fuel on the same timetable as standard fuel). Accordingly, the key inquiry is whether it was technically feasible in the non-breach world for DOE to accept and dispose of NSVY's short-cooled fuel on the schedule proffered by Plaintiff. *NSVY*, 159 Fed. Cl. at 587.

2. It Was Technically Feasible for DOE to Accept Short-Cooled Fuel.

Plaintiff showed by preponderant evidence that in the non-breach world it would have been technically feasible for DOE to accept and dispose of the minimal amounts of short-cooled fuel at Vermont Yankee during the claim period at issue. As an overall matter, the maturity of the exchanges market in a non-breach world, after 16 years of program operation, means the market would most likely be able to accommodate evolving market needs, including, in the Court's view, short-cooled fuel. *See* Easton, Tr. at 226:20–24; Supko, Tr. at 349:17–19; Brewer, Tr. at 1663:8–12. As Mr. Graves explained, both the slack in DOE's increasing capacity, annually and cumulatively, for the acceptance of SNF since at least 2004 and the relative predictability of the utilities' SNF storage needs over time, given the available public data on discharge patterns and storage capacity at each nuclear power plant, support the conclusion that a mature exchanges market more likely than not could accommodate limited short-cooled fuel pickup needs. Graves, Tr. at 886:24–887:3, 911:1–4, 911:10–12, 924:22–925:10, 926:2–11, 972:19–973:17, 974:4–19.

As discussed below, the Court finds compelling the following facts: the commercial feasibility of handling and shipping short-cooled fuel, DOE's planning for "other than standard"

fuel in its early cask design initiatives and designs for surface aging facilities at the repository, and the uncontroverted fact that no DOE statement, documentation, or guidance corroborates the Government's position that DOE would simply have refused to accept any and all short-cooled fuel because such fuel eventually converts to standard fuel with the passage of time. As well, the Court finds the Government's arguments based on its interpretation of the terms "sole discretion" and "disposal" in the Standard Contract to be unavailing.

a. Commercial Handling and Shipping of Short-Cooled Fuel

First, it is undisputed that short-cooled fuel has been safely handled and shipped in the breach world. Easton, Tr. at 206:21–208:24. Mr. Earl Easton[9] testified that, since at least 1965, short-cooled fuel has been commercially shipped in the United States, with the NRC having certified at least seven shipping casks for shipment of fuel cooled for a period ranging from 150 days to two years. *Id.* at 207:11–15, 208:9–12; *see also* Supko, Tr. at 346:25–347:22.

There is no regulatory scheme or prohibition against the shipping of short-cooled fuel, assuming proper NRC licensing is obtained and only NRC-certified casks are used in transport. *See* Easton, Tr. at 201:3–202:1, 202:14–21, 212:3–24 ("no regulations that limit cooling time"); Supko, Tr. at 330:1–3 ("[T]here is nothing in the regulations that governs the age of the fuel that can be shipped."). There also are no technical limitations for the handling, packaging, or shipment of short-cooled fuel as compared to standard fuel. *See* Swanger, Tr. at 100:8–25, 101:1–5 (nothing different or unique about loading short-cooled fuel assemblies into a cask); Supko, Tr. at 332:23–333:4 (no physical difference between short-cooled and standard assemblies although there may be a difference in decay heat), 337:24–338:24 (no difference in handling, storage, or transport of

[9] Mr. Easton was qualified as an expert in SNF cask design and certification, as well as SNF transportation, including associated regulatory requirements and technical considerations, and has over 30 years of experience at the NRC. Easton, Tr. at 169:15–25, 189:23–190:1.

spent fuel with high versus low decay heat as long as NRC-certified cask designed for those characteristics is employed). And while DOE's program planning was premised on casks with long 25-year lifespans that accommodate 10-year cooled fuel, such was based on operational efficiency concerns, not regulatory or technical limitations. Easton, Tr. at 213:1–215:11; Kouts, Tr. at 1419:11–22, 1421:7–16; 1986 RFP for Development of From-Reactor Casks at 59838, 59844–45, DX 3023. After all, short-cooled fuel was regularly shipped commercially prior to 1983 without issue. Easton, Tr. at 207:2–7.

Moreover, several witnesses, including the Government's witness, Mr. Christopher Kouts, a former DOE official with 25 years of experience in the Office of Civilian Radioactive Waste Management ("OCRWM"), which was created to implement the NWPA, and the Government's expert, Mr. Warren Brewer,[10] testified that the shipping of short-cooled fuel is technically feasible. Kouts, Tr. at 1364:20–25, 1483:9–22 (confirming that "shipping of short-cooled fuel is technically feasible in NRC certified casks" and there are not "any minimum cooling times or regulatory impediments to the NRC or other constraints on licensing or transportation casks to transfer short-cooled fuel"); Brewer, Tr. at 1619:6–16 ("You can ship short-cooled fuel. We've done it."). Evidence of routine commercial shipments of short-cooled fuel thus favors finding that it was technically feasible to handle and transport short-cooled fuel, and further that it was technically feasible for DOE to accept short-cooled fuel under the waste management program.

[10] Mr. Brewer was qualified as an expert in, among other things, nuclear plant operations and maintenance; nuclear plant modifications; nuclear spent fuel management, including dry storage; and nuclear decommissioning, including planning and cost estimation. Brewer, Tr. at 1550:20–1551:1, 1555:3–5.

b. DOE Program Planning: Cask Design Initiatives

Second, early planning documents for the DOE Cask Acquisition Program indicate that DOE contemplated the acceptance and transportation of nonstandard fuel, including short-cooled fuel.

As a part of its obligations under the NWPA to establish a national system to dispose of SNF and HLW, DOE planned to develop and acquire a fleet of NRC-certified casks for the transportation of civilian nuclear waste to a geologic repository. Easton, Tr. at 173:11–24; *see* 1986 DOE Transp. Bus. Plan at 1, 3, 5, PX 3009. In phase I of the DOE Cask Acquisition Program (or the "Transportation Systems Acquisition Task"), the OCRWM was to contract with private industry for cask development, certification, and prototype fabrication of the transportation fleet. PX 3009 at 3, 4. Phase I consisted of three cask development initiatives, of which Initiatives 1 and 3 are relevant to the issues presented here. *Id.* at 4.

Initiative 1, to be completed by 1993, focused on the development of casks for the shipment of standard fuel, which covered "most of the radioactive waste from reactors." *Id.* at 3; *see id.* at 17, 24. The aim of these casks was to "maximize payload and to minimize life-cycle costs while complying with all safety-related requirements." *Id.* at 17. Initiative 3, to be completed around 2001, focused on the development and procurement of "*specialty casks for nonstandard fuel* and non-fuel hardware destined for repository disposal." *Id.* at 3 (emphasis added); *see id.* at 16, 27, 29. As noted above, under the Standard Contract, "Class NS-3: short-cooled" fuel is one of the five categories of nonstandard fuel. JX 1 at 44; Easton, Tr. at 222:5–8. Initiative 3 specialty casks were aimed at accommodating nonstandard fuel and materials that could not be efficiently transported in casks developed under prior initiatives or in NRC-certified casks developed independently by private companies. PX 3009 at 27. Depending on what would be most efficient

and cost-effective, DOE was considering several options in Initiative 3 to deal with nonstandard fuel and non-fuel materials, "such as assembling a fleet of casks with valid NRC certificates of compliance; amending the NRC compliance certificates of casks developed under Initiative 1 or developed independently by the bidder; or establishing new specialty casks." *Id.* at 5; *see id.* at 27. Cask designs in Initiative 1 were projected to be NRC-certified by 1990, while amended cask designs used in Initiative 3 to accommodate nonstandard fuel were to be NRC-certified by 1996, and any new specialty casks used in Initiative 3 were to be certified by 1998. *Id.* at 23, 29. Initiative 1 cask procurement began in 1986, and many companies submitted designs; however, no casks were built under the Cask Acquisition Program because it was terminated by 1996. Easton, Tr. at 226:11–13; Supko, Tr. at 342:16–22.

Plaintiff's experts, Mr. Easton and Ms. Eileen Supko,[11] both point to Initiative 3 of the Cask Acquisition Program in the Transportation Business Plan as support for their opinions that DOE could accommodate all of VYNPS's short-cooled fuel needs. Easton, Tr. at 220:16–222:8; Supko, Tr. at 340:18–341:5, 342:2–13. Mr. Easton noted that under either option—that is, an amended existing cask or a new specialty cask—DOE projected that Initiative 3 casks would be built by no later than 2002. Easton, Tr. at 221:20–222:4, 224:3–7. Specifically, Mr. Easton testified that if an existing Initiative 1 cask design was amended for Initiative 3, the amended cask design could be NRC-certified by 1996 and "fabrication could have been done by 1998," *id.* at 223:11, while any new specialty cask design could be NRC-certified by 1998 and built by 2002, *id.* at 221:20–222:4, 223:6–13. Although no casks for DOE were ultimately built, Ms. Supko

[11] Ms. Supko was qualified as an expert in SNF storage and transportation, including associated regulatory requirements, technical considerations, and loading activities for SNF storage and transport, as well as the DOE's Civilian Radioactive Waste Management System, including SNF acceptance and transportation. Supko, Tr. at 322:13–19, 323:6–8.

opined that from her experience, including her examination of DOE studies and existing NRC-certified casks to transport short-cooled fuel, Initiative 3 (or something similar) could have adequately addressed the short-cooled fuel needs of VYNPS on the timeline offered by Plaintiff. Supko, Tr. at 343:8–15.

Mr. Kouts asserted that Mr. Easton and Ms. Supko misinterpret Initiative 3. Kouts, Tr. 1412:18–25. In Mr. Kouts' experience, Initiative 3 was "really for the cats and dogs, the nonfuel-bearing components," including "control spiders, poison rod assemblies, control rod elements[,] . . . things that were left in the pool that utilities wanted out[,]" and more specifically for nonstandard fuel assemblies from a South Texas plant which would not fit, dimensionally, into a standard cask. *Id.* at 1408:13–1409:5, 1412:18–1413:24. Yet, the language of the Transportation Business Plan does not limit Initiative 3 to "non-fuel bearing components" and "nonstandard fuel" from a single South Texas plant, as Mr. Kouts claims. *See* PX 3009 at 3; *see also id.* at 16, 27. Notably, in the cask design descriptions for Initiative 3, "nonstandard fuel" is listed separately from "non-fuel hardware" or "non-fuel materials," *id.*, which establishes that the items are distinct, supporting the interpretation that DOE specifically planned for shipping nonstandard fuel, including short-cooled fuel, in addition to "cats and dogs." And Mr. Kouts admitted on cross-examination that there is no documentation to corroborate his view of the limitations on Initiative 3. *See* Kouts, Tr. at 1490:5–11.

Mr. Easton, who was involved on the NRC side with the Cask Acquisition Program, presented a more credible view, stating that the NRC, based on communications with DOE, "planned on potentially certifying casks for all of the categories of nonstandard fuel," including for short-cooled fuel. Easton, Tr. at 217:13–19. Both he and Ms. Supko similarly testified that they were unaware of any DOE statement or document that suggested DOE would not accept short-

cooled fuel. *See id.* at 217:22–218:1 (explaining DOE did not advise that it intended to exclude a class of fuel such as short-cooled fuel), 244:24–247:1 (same); Supko, Tr. at 363:18–364:1, 368:23–369:3. Based on the foregoing, the Court finds Mr. Kouts' testimony that Initiative 3 was only meant to address certain non-fuel components to be not credible.

The Government next highlights that Plaintiff's timeline (per the Graves model) shows 120 MTUs of short-cooled fuel being removed from VYNPS in the first two years of the program, even though any specialty cask under Initiative 3 would not have been available until the early 2000s. Def.'s Post-Trial Br. at 29, ECF No. 104 (citing Kouts, Tr. at 1413:7–18; Graves, Tr. at 1044:6–12; PX 3009 at 29). The Court credits Mr. Easton's testimony that an amended cask design from Initiative 1 was expected to be NRC-certified by 1996, as confirmed by the Initiative 3 timeline, PX 3009 at 29, and further, that such cask could have been built within two years by 1998, when the program was scheduled to begin operating. Easton, Tr. at 223:6–13; *see also* Kouts, Tr. at 1492:1–13 (agreeing that amending COCs to accommodate higher burnups and enrichments with standard fuel is the same process as amending COCs to accept short-cooled fuel). Therefore, if cask design initiatives and fleet acquisition progressed in line with the Transportation Business Plan, Initiative 3 casks based on amended designs likely could have accommodated short-cooled fuel even in the early years of the program. *See* Supko, Tr. at 351:8–14 (the HI-STAR 80, as well as casks from the 1970s and 80s, show it would have been possible to design a cask to transport short-cooled fuel). Moreover, as will be addressed further in the next section, moving 120 MTUs of short-cooled fuel in the early years of the program would have been relatively minor considering what the Yucca Mountain repository and its surface aging facilities were being designed to accommodate.

c. DOE Program Planning: Surface Storage/Aging Facilities

Third, evidence related to the planning of the Yucca Mountain repository indicates that DOE contemplated interim storage of nonstandard fuel, including short-cooled fuel, in surface aging facilities, as necessary, before moving the fuel into the repository. Mr. Easton testified that Yucca Mountain planning documents submitted for purposes of NRC licensing expressly discussed the packaging, receipt, and storage of short-cooled fuel using interim wet storage or aging facilities. *See* Easton, Tr. at 250:13–255:20. In a draft document prepared on the functional and operational requirements for Yucca Mountain, a chart outlined precisely how DOE intended to handle all types of fuel, which specifically included Class NS-3 short-cooled fuel. *See id.* at 250:9–251:3. The chart stated that short-cooled fuel would be transported as "[b]are assemblies in standard shipping casks or canisters," *id.* at 251:7–251:11, and that, at the repository, "the assemblies may be moved to [the] remediation building for wet storage and returned to the dry storage once they have been cooled," *id.* at 252:5–8. Mr. Easton also noted that, unlike other categories of nonstandard fuel, the shipper was not required to notify DOE one year in advance of "any handling method" needed. *Id.* at 252:18–24. In Mr. Easton's opinion, this would be consistent with the expectation in the Transportation Business Plan that short-cooled fuel may be shipped by modifying existing Initiative 1 casks, and thus the handling procedures would be the same and any notice redundant. *Id.* at 252:24–253:8.

In a similar planning document, another chart provided an overview of the Yucca Mountain license process wherein all five classes of nonstandard fuel, including Class NS-3: short-cooled fuel, were specifically listed. *See id.* at 253:11–20. Under the column titled "transportation requirements," the chart stated that there were "no regulatory requirements limiting the movement of nonstandard SNF" except compliance with the cask's COC. *Id.* at 253:25–254:3. Under the

column titled "where addressed in the [license application]," aging facility is enumerated as responsive to the fuel discussed in the "NS-3" fuel row. *Id.* at 255:2–15. These Yucca Mountain planning documents confirm that DOE was planning for acceptance and disposal of short-cooled fuel in its repository designs, and thus that acceptance and disposal of short-cooled fuel was technically feasible.

The Government's evidence to the contrary is unpersuasive. The Government argues that the repository was not designed to handle short-cooled fuel and that the surface storage facilities at the repository were only intended to receive fuel from the transport cask and transition it into a waste package that would be placed in Yucca Mountain. *See* Kouts, Tr. at 1440:4–25, 1444:11–15. Based on the character of the assemblies in the cask, *i.e.*, burnup, age, and general condition, the program would determine whether the fuel should be stored or aged first or whether it could be placed directly in a waste package. *See id.* at 1440:11–25. According to Mr. Kouts, any aging at the surface facilities only applied to standard fuel that may have a "higher burnup or for whatever reason" needed to be put aside and stored for a period until it was cool enough to be integrated with other assemblies and placed in the mountain. *Id.* at 1442:2–8; *see id.* at 1493:7–8 ("[W]e contemplated storage for standard fuel in terms of aging[.]"). As Mr. Easton explained, however, the process to cool nonstandard short-cooled fuel is similar to the process of cooling standard fuel, and in some circumstances standard fuel assemblies can have higher decay heats than short-cooled assemblies. *See* Easton, Tr. at 249:23–24; *see also* Supko, Tr. at 333:7–10; Kouts, Tr. at 1507:18–1508:7 (acknowledging that heat load and doses for standard fuel could in some instances be higher than for short-cooled fuel, depending on the specifics of the fuel).

Mr. Kouts also insisted throughout his testimony that DOE did not plan to accept fuel cooled less than five years at the repository because that was not in the repository's design basis,

and that DOE never contemplated that surface facilities would be used to age short-cooled fuel because they were limited in capacity. Kouts, Tr. at 1441:1–16 (capacity for surface facilities was limited and expanding it "would create lots of issues [with] licensing"), 1444:11–23, 1481:25–1483:16 ("[N]o matter what the contract says[,]" the Government was "not going to take [fuel] until it's cooled for at least five years."), 1509:16–19.[12] DOE planning documents identify the program's design assumptions. The assumptions, including that the emplaced fuel have a minimum cooling age of five years, were intended to maximize "system-component capability" and were subject to "adjust[ment] as future conditions warrant." *See* June 1985 Mission Plan at -1126, DX 3018; *id.* at -1127 (noting that the waste age "is assumed to have a minimum cooling age of 5 years"); June 1987, Vol. I: Analysis on Total Sys. Life Cycle for Waste Mgmt. at -29751, DX 3027 (discussing five-year fuel age constraint). Standard fuel cooled for at least five years amounted to 90 percent of SNF that would be shipped from utilities across the country. Easton, Tr. at 177:7–13. But the decision to design the repository based on the characteristics of *the vast majority* of the fuel to be accepted under the program does not in and of itself demonstrate that acceptance of *any amount* of short-cooled fuel was infeasible, especially in light of the licensing evidence discussed above which contemplated short-cooled fuel. Indeed, on cross-examination, Mr. Kouts acknowledged that in a 2008 iteration of the Yucca Mountain license application, the surface aging facilities were designed to accommodate 21,000 MTUs in capacity and 2,500 aging spaces and that in earlier iterations, the repository would have had larger wet pools or even dry storage for long periods of aging. Kouts, Tr. at 1501:16–19; *see id.* at 1501:9–15 (noting DOE would be providing transportation, aging, and disposal ("TAD") canisters which would be loaded

[12] The only situation Mr. Kouts could identify that would warrant DOE's acceptance of short-cooled fuel was a national emergency event. Kouts, Tr. at 1431:17–21.

at reactors, transported to the repository, and placed on an aging pad within the repository), 1503:9–14 (earlier versions of the repository conception contemplated dry storage outside the repository to support aging for a long period of time). This evidence indicates that facilities for the aging of SNF have been a consistent theme in DOE repository designs, which supports the finding that DOE could technically have accommodated some amount of short-cooled fuel that required aging.

As to capacity and space limitations, the Government argues that accommodating 120 MTUs of short-cooled fuel in the first two years of the program would not have been technically feasible. The evidence shows otherwise. Per annual DOE waste acceptance rates, the repository was set to accept 1,200 MTUs each in 1998 and 1999, or cumulatively 2,400 MTUs by 1999. DX 3025 at 60–61; *see Pac. Gas I*, 536 F.3d at 1291. While the program was more constrained in the early years, DOE more likely than not could have accepted 120 MTUs of short-cooled fuel, as it amounts to only five percent of the aggregate DOE program capacity, Graves, Tr. at 1044:3–12, and less than one percent of the projected 21,000 MTU-capacity of the repository's surface aging facilities. While this conclusion relies on Mr. Kouts' testimony regarding a later iteration of the Yucca Mountain license application to estimate what the repository could handle for "aging" and, arguably, such estimation may be imprecise, the Government cannot insist on proof that by reason of its breach is unobtainable. *See Locke*, 283 F.2d at 524.

d. Impact on DOE's Capacity to Pick Up SNF from Other Utilities

Fourth, contrary to the Government's argument that accepting short-cooled fuel would have placed tremendous strain on the program (ECF No. 104 at 24, 29–30; *see* Kouts, Tr. at 1436:17–1437:22), Plaintiff has shown that the waste management program had adequate capacity during the 2014–2018 claim period to accept all VYNPS's short-cooled fuel, as well as the short-

cooled fuel from other shutdown utilities. In Plaintiff's model of a hypothetical non-breach world, DOE would have handled 64 additional cask shipments between 2014 and 2016 due to increased short-cooled fuel demands from the three plant shutdowns: 19 casks from Kewaunee in 2014, 14 from Vermont Yankee in 2016, and 31 casks from San Onofre in 2016. Supko, Tr. at 378:13–379:15, 380:3–16. If "blending" strategies were employed, no additional shipments would have been required, and there would have been almost no impact on the DOE program. *Id.* at 377:20–378:24, 380:7–16.[13] The Court agrees that, whether by blending or additional shipments, the DOE program could have accommodated the short-cooled fuel required during the relevant claim period.

But even assuming 64 additional shipments, or approximately 640 MTUs (190 MTUs in 2014 and 450 MTUs in 2016),[14] were required without blending, the Court finds it would have been technically feasible for the DOE program, which would have been fully functioning for over a decade, to accept the short-cooled fuel in the claim period. From 2008 onwards, the DOE program would accept 3,000 MTUs per year. DX 3025 at 60–61; *Pac. Gas I*, 536 F.3d at 1291. In the aggregate, the DOE program would have accepted 39,600 MTUs by 2014, 42,600 MTUs by 2015, and 45,600 MTUs by 2016. DX 3025 at 60–61. One hundred and ninety MTUs of short-cooled fuel would have amounted to approximately 6.3 percent of DOE's 2014 acceptance capacity, and 450 MTUs of short-cooled fuel would have amounted to approximately 15 percent of DOE's 2016 capacity. *See* Supko, Tr. at 380:17–25. The program and the exchanges market

[13] "Blending" is a technique that can be used to manage the transportation and storage of short-cooled fuel. Easton, Tr. at 205:14–19. Specifically, cold fuel assemblies are placed around hotter fuel assemblies in a cask's package or fuel basket in particular configurations to control the heat or radiation dose rates. *Id.* at 205:8–19; Supko, Tr. at 335:1–16. The concept of blending has been around since the early 1990s; and in the real world, blending is used extensively when plants transition to dry storage. Supko, Tr. at 336:9–20, 377:17–19, 415:2–19.

[14] For ease of calculating, the Court assumes an average of approximately 10 MTUs per cask. *See* Graves, Tr. at 941:16.

more likely than not could have accommodated such modest amounts with appropriate planning. And in terms of DOE's 2016 aggregate acceptance capacity, the total amount of short-cooled fuel to be shipped from the shutdown plants (640 MTUs) is relatively minor, less than two percent. *See* Easton, Tr. at 257:14–24, 258:22–259:10; Supko, Tr. at 381:4–382:1.

It is important to place in perspective that the vast majority of the fuel that would have been shipped and accepted by the DOE waste management program was standard fuel. *See* Supko, Tr. at 332:1–4 ("The majority of the inventory would have been standard fuel, but a small amount would have been short-cooled fuel, and that was primarily the final core and the prior two . . . discharges."); Graves, Tr. at 1102:7–24 (explaining that operating plants would not routinely ship short-cooled fuel, and that the short-cooled demand only arises when a shutdown plant wants to move everything out of its pool). For example, over its plant life, Vermont Yankee had about 3,880 total assemblies that needed to be transported. Supko, Tr. at 352:13–24. Of that amount, only 604 assemblies were nonstandard fuel, including short-cooled fuel. *Id.* at 353:15–18, 356:8–14. By the 2014 shutdown, only 2,148 assemblies (604 of which were short-cooled assemblies) would have remained in the spent fuel pool. *Id.* at 353:12–18. Assuming transport of the remaining fuel assemblies began in 2016, Ms. Supko estimated that it would take only 46 total (unblended) cask shipments to empty the pool at Vermont Yankee. *Id.* at 360:1–8. Ms. Supko further opined that the 46 cask shipments could have been achieved in 184 days, with 6 months flexibility. *Id.* at 360:11–19, 361:2–11. Given that DOE would be shipping 3,000 MTUs/year, 46 casks from Vermont Yankee would not likely have had a material impact on the DOE program. *See id.* at 362:2–7, 382:17–21.

e. No Corroborating DOE Documentation

Lastly, as Plaintiff aptly points out, there is "no contemporaneous corroborating written statement, directive, or communication to the industry" in line with the Government's position that DOE had no intention to accept short-cooled fuel and would simply wait to accept the fuel once it became standard fuel. ECF No. 102 at 50; *see* ECF No. 104 at 20; Kouts, Tr. at 1481:14–1482:24 ("[W]e're not going to take it until it's cooled for at least five years."). Since its inception, reams of paper have been generated on DOE's waste acceptance program and submitted as evidence in SNF cases like this one. Yet no witness at trial could point to a single statement or document indicating that DOE would not accept an entire category of nonstandard fuel, even though it is specifically obligated to in the Standard Contract. *See, e.g.*, Easton, Tr. at 217:22–218:1; Supko, Tr. at 363:18–364:1; Kouts, Tr. at 1486:19–1487:9.

In the Court's view, this is telling. If short-cooled fuel was to be treated differently than other nonstandard fuel (beyond technical feasibility considerations) and not accepted until it became standard fuel, a provision to that effect could have been included in the Standard Contract or, at the very least, one would expect that position to have been clearly communicated in the many statements made to the public and the industry about DOE's program planning. Instead, even Mr. Kouts stated in a presentation to the Nuclear Waste Technical Review Board, a board that oversees the program, that "all bare spent fuel (regardless of type and condition) is acceptable" and that DOE's obligations under the Standard Contract extended to "other than standard" spent nuclear fuel, subject to delivery and handling procedure confirmation. Kouts, Tr. at 1484:8–1486:4. And further, DOE stated in responses to public comments that the acceptance of nonstandard fuel, which includes short-cooled fuel, would be treated on a case-by-case basis (*i.e.*, if technically feasible). Rec. of Resps. to Pub. Comments on Draft Mission Plan at -1138, DX 3019 (explaining

that standard fuel has a minimum cooling time of five years, and that nonstandard fuel would be "treated on a case-by-case basis"). When viewed in the context of the record as a whole, this evidence, or rather lack thereof, diminishes the weight the Court assigns to the testimony of the Government's witnesses.

Based on the foregoing, the Court concludes that it was technically feasible for DOE to accept VYNPS's short-cooled fuel and to do so on the timeline Plaintiff presented.

3. The Government's "Sole Discretion" and "Disposal" Arguments Are Unavailing.

Notwithstanding the obligation to accept all types of fuel, the Government emphasizes its "sole discretion" to approve an exchange request under the Standard Contract as evidence that Plaintiff's damages theory must fail. ECF No. 104 at 17 (citing JX 1 at 12 (Art. V.E)). Specifically, the Government argues that Plaintiff offers no evidence that DOE would approve "a single one of its exchanges consisting of short-cooled fuel" and contends that the Court's review of that exercise of discretion is narrow, only to be disturbed based on a violation of the implied duty of good faith and fair dealing. *Id.* at 17–19. While it acknowledges that "a blanket prohibition on all exchanges" would violate such duty, the Government contends that DOE "is squarely within its discretion to disapprove exchanges for a single type of non-standard fuel, that will later become standard, and which the program was never designed to accept." *Id.* at 20. The Court disagrees to the extent that the contemplated exchanges involved short-cooled fuel that was technically feasible to accept on the same schedule as the exchanged DCSs.

The relevant portion of the Standard Contract provides: "Purchaser shall have the right to exchange approved [DCSs] with parties to other contracts with DOE for disposal of SNF and/or HLW; *provided, however*, that DOE shall, in advance, have the right to approve or disapprove, in its sole discretion, any such exchanges." JX 1 at 12 (Art. V.E) (emphasis in original). Courts in

other SNF cases have previously rejected the notion that DOE could exercise its discretion under the Exchanges provision in such a way as to swallow DOE's acceptance obligation itself; rather, DOE is expected to exercise its discretion reasonably. *E.g.*, *Pac. Gas & Elec. Co. v. United States* (*Pacific Gas II*), 92 Fed. Cl. 175, 187 (2010), *aff'd*, 668 F.3d 1356 (Fed. Cir. 2012); *Yankee Atomic*, 679 F.3d at 1360; *see* Order on Mot. in Limine at 5, ECF No. 77. Moreover, the cases that the Government relies on to argue for a narrow review of DOE's exercise of discretion are inapposite to the case at bar. Those cases involved the review of agency discretion exercised pursuant to contracts that the Government was *performing*, and not, as here, where the Government has breached a contract and the Court is evaluating the hypothetical exercise of discretion in a non-breach world. *See 27-35 Jackson Ave, LLC v. United States*, 162 Fed. Cl. 550, 553 (2022) (GSA "concluded the premises were untenable and exercised a contractual right to terminate the lease"); *Suwannee River Fin., Inc. v. United States*, 7 Cl. Ct. 556, 559 (1985) (Maritime Administration "halted all subsidy payments for non-essential changes" due to a decrease in the budget); *Solaria Corp. v. United States*, 123 Fed. Cl. 105, 110 (2015) (government permitted to withdraw from contractual loan commitment where parties never reached a formal loan agreement); *N. Star Alaska Hous. Corp. v. United States*, 30 Fed. Cl. 259, 269–70 (1993) (government "determination" of reimbursable damages under lease clause).

The Court finds that DOE would not exercise its discretion reasonably if it denied approval for exchanges of an entire subset of fuel, despite its legal obligation to accept such fuel under the contract and absent technical feasibility concerns that would warrant schedule adjustment. Such a "blanket prohibition," even if only as to a subset of fuel, is per se arbitrary and violates any notion of good faith and fair dealing. Here, the Court has already held that DOE's legal obligation under the Standard Contract extended to short-cooled fuel and that it was technically feasible for DOE

to accept VYNPS's short-cooled fuel on the timeline proposed. *See supra* § II.B.1. The Government has presented no reasonable basis to otherwise withhold approval under the Exchanges provision. Therefore, its "sole discretion" argument again fails.

So too does its "disposal" argument. The Government contends that the question of "technical feasibility" applies to the disposal of nonstandard fuel as defined in the Standard Contract and thus at issue is how short-cooled fuel would be disposed of by DOE at the repository. ECF No. 104 at 24–26; *see* Trial Tr. at 1104:25–1116:3 (arguments of government counsel on Rule 52(c) motion); *see also* JX 1 at 14 (Art. VI.A.2(b)) ("DOE's obligation for *disposing of* SNF . . . also extends to other than standard fuel . . . . DOE shall advise Purchaser . . . after receipt of such confirmation request as to the technical feasibility of *disposing of* such fuel on the currently agreed to schedule and any schedule adjustment for such services.") (emphases added)). "Disposal" is defined in the Standard Contract as "the emplacement in a repository . . . with no foreseeable intent of recovery[.]" JX 1 at 3 (Art. I.8). The Court has already found that it was technically feasible for DOE to accept, transport, and process short-cooled fuel for disposal in the context of the DOE's waste acceptance program, considering (among other evidence) that DOE's early plans specifically contemplated the acceptance and disposal of short-cooled fuel via Initiative 3 casks and its repository aging facilities. The Court is not convinced that its finding is inconsistent with the definition of "disposal," even if it is possible that short-cooled fuel would require some aging before literal emplacement in the repository.

In any case, the attempt to use the definition of "disposal" to evade the legal obligation to accept SNF has been previously rejected. *See Ind. Mich. Power Co. v. U.S. Dep't of Energy*, 88 F.3d 1272, 1275–76 (D.C. Cir. 1996). In *Indiana Michigan*, several states and utilities challenged a DOE Final Interpretation concluding that the agency did not have a statutory or contractual

obligation to begin accepting SNF in 1998 in the absence of an operational repository or interim storage facility. *Id.* at 1274. The pertinent provision of the NWPA states that "in return for the payment of fees . . . [DOE], beginning not later than January 31, 1998, will dispose of the [SNF] . . . ." *Id.* (quoting NWPA § 302(a)(5)(B), codified at 42 U.S.C. § 10222(a)(5)(B) (1994)). The D.C. Circuit held that the common understanding of the phrase "dispose of" means "to get rid of; throw away, or discard," and, further, that the duty to "dispose of" SNF in the NWPA is not tied to the commencement of repository operations. *Id.* at 1275. It rejected the Government's attempt to limit its duty in accordance with the definition of the term "disposal" in the NWPA, which means "the emplacement in a repository of . . . [SNF] . . . with no foreseeable intent of recovery." *Id.* (quoting 42 U.S.C. § 10101(9)). As the court explained, although the restrictive definition of "disposal" conditioned DOE's obligation to take title to SNF on the commencement of repository operations, it had no bearing on DOE's duty to "dispose of" SNF in exchange for the utilities' payment of fees. *Id.* at 1276. The non-existence of a repository only affected the remedy a court could provide for a breach of DOE's duty. *Id.* at 1277.

The definitions of "disposal" in the NWPA and the Standard Contract are almost identical. *Compare* 42 U.S.C. § 10101(9) *with* JX 1 at 3 (Art. I.8). And the specific term at issue here—"disposing of"—is akin to the term "dispose of" in *Indiana Michigan*. *Compare* 42 U.S.C. § 10222(a)(5) *with* JX 1 at 14 (Art. VI.A.2(b)). Just as in *Indiana Michigan*, DOE cannot evade its obligation to dispose of nonstandard fuel, including short-cooled fuel, based on the "availability of a facility" for disposal. 88 F.3d at 1277 ("We agree with DOE that Congress contemplated a facility would be available by 1998; however, that Congress contemplated such a facility would be available does not mean that Congress conditioned DOE's obligation to begin acceptance of SNF on the availability of a facility."). The same reasoning would apply here.

4. The Graves Model Establishes that Wet Pool Storage Costs Between 2017 and August 2018 Are Recoverable.

The remaining issue is whether Plaintiff, through the Graves model, has met its burden to establish a 2016 fuel-out date such that it may recover wet pool storage costs incurred from 2017 through August 2018, or whether the Government's criticisms render the Graves model unreliable. The Court finds that the Graves model sufficiently establishes that but for the breach DOE would have removed all SNF, including short-cooled fuel, from VYNPS by no later than the end of 2016.

Earlier versions of the Graves model have been accepted in prior SNF cases, although the model in the instant case is the first version that assumes short-cooled fuel would be accepted from shutdown plants. *E.g.*, *SMUD I*, 566 F. App'x at 994; *Dairyland Power II*, 645 F.3d at 1370; *Portland Gen.*, 107 Fed. Cl. at 645. The reason for this change in assumptions is the prevalence in more recent years of nuclear plant shutdowns. Graves, Tr. at 987:1–22 (explaining that one-year cooled fuel only becomes an issue when a plant is shut down because an operating plant always has older, cooler SNF in its pool to deliver). Mr. Graves clarifies that except for one or two shutdowns in the first few years of the waste acceptance program, short-cooled fuel is not an issue until about 10 years into the program when plants begin to shut down. *See id.* at 994:10–18.

In formulating the current model, like in prior cases, Mr. Graves relies on available data and information regarding the DOE program, utility storage needs, discharges, pool capacities, and potential costs, noting that the data is "unusually reliable" because of the "sustainability of operations in the nuclear industry and the quantity and quality of public information about its operations." *Id.* at 889:18–890:6, 921:23–922:7, 926:2–11; *e.g.*, 2004 APR & ACR at 2, PX 3066 (providing discharge histories from 1967 through 2002); Spent Fuel Storage Requirements 1994–2042, JX 5 (projecting plant discharges as compared to pool capacities); DX 3025 at 60–61 (DOE waste acceptance rates); *Yankee Atomic Power Co. v. United States*, 94 Fed. Cl. 678, 691–92

(2010). He also uses the same framework and principles in this model, but with updated information. Graves, Tr. at 884:13–20, 953:16–21 (current version of model updates results and assumptions every year). Fundamentally, the model remains a prediction of how "supply and demand for DOE SNF acceptance allocations would have created a market for their exchange." *Portland Gen.*, 107 Fed. Cl. at 643; *see* Graves, Tr. at 885:25–886:12, 1002:9–24.

The "supply" side of the model is fixed, based on DOE acceptance allocations set forth in the 1987 Mission Plan Amendment. *See, e.g.*, Graves, Tr. at 913:4–14; DX 3025 at 60–61 (waste acceptance rates: 1,200 MTUs/Year for 1998–2002; 2,000 MTUs/year for 2003; 2,650 MTUs/year for 2004–2007; and 3,000 MTUs/year thereafter); *Portland Gen.*, 107 Fed. Cl. at 643. The "demand" side, on the other hand, is driven by existing storage at the various utilities and two scenarios when storage costs increase at a utility due to, what Mr. Graves calls, "must move" conditions. Graves, Tr. at 918:10–18, 921:2–7. The first condition is when the utility's wet pool reaches full core reserve, at which point it must either build storage or shut down operations because it cannot safely exceed the pool capacity. *Id.* at 918:17–919:23. The second condition is when a nuclear plant shuts down, in which case it incurs the O&M costs of managing a wet pool that is no longer necessary to operations. *Id.* at 920:2–22. In the two "must move" scenarios—"full pool must move" and "shutdown must move"—there is an increased demand for fuel removal. *Id.* at 918:12–920:22, 921:2–10. In effect, the potential costs of addressing those "must move" storage needs, *i.e.*, dry storage construction, storage maintenance, or wet pool O&M costs, and the willingness to pay to address those needs, underlines the demand curve in the model. *Id.* at 928:5–929:3; *see also Portland Gen.*, 107 Fed. Cl. at 643.

In this version, the Graves model employs an analytic software that does the same calculations as prior versions of the model but in an "iterative, stepping forward, information-

adjusting way," rather than in a "static" manner limited to the perspective of the first year of the program—the 1997 perspective. Graves, Tr. at 957:24–958:2; *see id.* at 956:19–957:20. Mr. Graves adjusted the model in this way to respond to the Government's criticism of static modeling in prior cases, allowing him to conduct additional sensitivity analyses to address changing circumstances. *Id.* at 957:10–24.

As to the technical aspects of the current model, there are four modules that solve different aspects of the exchanges modeling problem to formulate a solution. *Id.* at 959:24–960:4, 962:13–18 (explaining the modules work together as a group and show a complete or useful picture as a whole). The first module "makes each year's adjustments to what the planned discharges and needs are going to be in the future" based on projected discharges. *Id.* at 960:4–10. The second module considers "what is the best use of the program capacity to try and minimize as many of the costs as possible," using an optimization software platform called GAMS. *Id.* at 960:11–21. In essence, this second module provides the preferred solution—*i.e.*, the best way to the use the capacity against the utilities' needs, *id.* at 961:5–7, while the third module ensures the suggested allocation is feasible by comparing the solution to the utilities' actual OFF rights, *id.* at 961:8–10. The final module filters the recommended reallocation from the other portions of the model, trims those rights and the amount of exchanges to be aligned with the amount of OFF rights that parties hold based on discharges, and charges a marginal cost based on what is feasible. *Id.* at 961:20–962:8, 1064:15–21.

Each year, the Graves model looks ahead 10 years and solves based on that year's outlook of needs and conditions. *Id.* at 935:7–17, 954:1–955:4. Using a 10-year planning horizon, only the first year is a physical commitment, while the remaining nine years project planning solutions for how the market might accommodate the upcoming needs. *Id.* at 954:17–23. At the start of the

following year, the model solves the problem again, but looking 10 years from that point to see if anything has changed, *e.g.*, new license extensions, shutdown decisions, or discharge rates. *Id.* at 954:24–955:15; *see also id.* at 959:5–10 (the 10-year horizon is industry practice, but an eight-year or 15-year horizon would have been acceptable). While the modeling mechanics have been updated, the goal of the analysis—finding the intersection of the supply and demand curves with price set by economic priority or willingness to pay—is the same. *See id.* at 884:16–20.

Mr. Graves testified that from 1997 onwards only small changes occurred each year in the model; however, in 2004, when utilities decided to extend their licensing, the shutdown must move needs were delayed, causing the cumulative demand curve to decrease. *Id.* at 935:18–936:11. Thereafter, in 2014, unexpected plant shutdowns caused an increase in the cumulative demand curve in the model, and this occurred again in 2019 with the next wave of shutdowns. *Id.* at 936:15–17. Given the stable supply curve from DOE program acceptance rates, however, even the substantial changes in demand do not impede the program's ability to address the industry's needs because of persistent slack from 2004 onwards. *Id.* at 936:18–24; *see id.* at 942:13–18 ("[B]y 2004 and thereafter . . . the program has excess capacity and constantly meets everyone's needs[.]"). As a result of this slack, or excess supply based on DOE acceptance capacity in the market, the Graves model assumes that after 2004 there are no transaction costs for participating in exchanges. *Id.* at 893:3–16, 911:1–10, 911:21–25 (noting the program is constrained from 1998 to 2004 because the program had less capacity than the industry wanted, but by 2004 the problem goes away because the market has persistent slack for decades and transactions are free and abundant). This assumption is consistent with the court's finding in *Portland General Electric*, which held that prior to 2005 "[t]he value of allocation rights would have approached a nominal value once supply exceeded demand." 107 Fed. Cl. at 653; *see id.* ("Mr. Graves' analysis shows

that the supply of exchange allocations would exceed demand for them at some point prior to 2005. In short, under no circumstances would the last date for removal of SNF be later than 2005.").

The Graves model ultimately determines that Plaintiff would have been able to exchange its acceptance rights such that DOE would have removed all SNF from VYNPS by no later than 2016, without incurring any cost to use exchanges. Graves, Tr. at 892:25–893:16. And Mr. Graves explained that even if DOE had issues with approving any exchange, given the slack in the industry, there would have been many other trading partners in the same year, allowing sufficient flexibility to adjust as needed. *Id.* at 951:15–21, 1081:18–1082:4.

Based on its evaluation of the Graves model presented in this case, the Court finds that Mr. Graves reliably models a robust exchanges market and persuasively concludes, based on the model, that DOE would have removed all SNF, including short-cooled fuel, from the Vermont Yankee plant by no later than the end of 2016. The Court agrees that it is more likely than not that a robust and mature market of exchanges would have developed by 2014, including to accommodate the limited amounts of short-cooled fuel from utilities faced with a "must move" scenario, especially given the persistent slack in excess DOE acceptance capacity for over a decade and the willingness of the parties, including DOE, to facilitate exchanges in light of the significant cost savings and logistical efficiencies as compared to the OFF schedule. As well, the Court agrees that the value of exchanges would have been zero, or at the most nominal, since the supply would have exceeded demand for over a decade by the claim period at issue.

5. The Government's Criticisms of the Graves Model Are Uncompelling.

The Court finds the Government's criticisms of the Graves model unavailing.[15] The

[15] Certain challenges to the Graves model have been discussed at length above, and thus, the Court will not address them again, *i.e.*, the acceptance of short-cooled fuel, the approval of

Government argues that the Graves model is unreliable because it (1) overstates supply, relying only on DOE's program capacity each year and random allocation of slack, ECF No. 104 at 28, 33; (2) understates demand, relying on only the utilities' costs and incorporating just-in-time SNF management or perfect foresight and hindsight, *id.* at 33; (3) assumes universal participation by utilities and uniform storage costs, *id.* at 39; and (4) focuses on cost optimization, or reducing utilities' at-reactor costs, and thus produces results inconsistent with individual plants' OFF rights and prior Graves models, *id.* at 32–36.

a. Supply

In the Graves model, supply is equal to the DOE program capacity. Dr. Gurrea argues that this is an oversimplification because it is "unrealistic to assume[] that the total program capacity would be available to a market of exchanges." Gurrea, Tr. at 1813:18–20. As a result, he criticizes Mr. Graves both for overstating demand and for randomly and proportionally allocating excess capacity as "slack" among the utilities. *Id.* at 1790:12–18, 1795:18–21, 1814:18–19.

Equating supply to program capacity is not novel. It has been a feature across the Graves model presented and accepted in prior cases, as Dr. Gurrea admits. *Id.* at 1906:15–17; *see, e.g.*, *SMUD II*, 566 F. App'x at 990; *Portland Gen.*, 107 Fed. Cl. at 643–44. Moreover, due to the Government's breach, the Federal Circuit established DOE's waste acceptance rates based on the 1987 ACR process because it was the "most accurate picture of the parties' intent . . . when both parties still anticipated timely and full performance of the contract." *Pac. Gas I*, 536 F.3d at 1290–91. As such, the Court finds it reasonable to rely on those rates in modeling supply in a non-breach

exchange requests, and the lack of transaction costs for exchanges. Additionally, the argument that the Graves model fails to incorporate a 10-year limit on the availability of DCSs or to account adequately for sociopolitical risk will be addressed in the next section in evaluating the Gurrea model's assumptions.

world. While Dr. Gurrea highlights that exchanges were only an option available to utilities (not a requirement), Gurrea, Tr. at 1768:4–6, Mr. Graves' explanation of the economic benefits of exchanges that would entice all utilities to participate is more persuasive than Dr. Gurrea's explanation of the factors he believes would constrain capacity, as more fully discussed below. *See infra* § II.C.3.

The Court also takes no issue with Mr. Graves' allocation of slack, which is in essence a bookkeeping function of the model. Graves, Tr. at 2120:5–8. Since supply is expected to exceed demand beginning in 2004, it is reasonable to assume that utilities would have allocated that slack, and one reasonable method of allocation would be based on how much fuel each utility had to move. *Id.* at 976:18–24. They could also have reasonably allocated it in other ways; due to DOE's breach we will never know. But that fact does not demonstrate that Mr. Graves' assumption is unreasonable. Accordingly, the argument that the model overstates supply fails.

b. Demand

The Government next argues that the Graves model understates demand because Mr. Graves defines it as some measure of the utilities' storage costs. ECF No. 104 at 33. According to Dr. Gurrea, because the Graves model incorporates the benefit of hindsight and perfect foresight it removes uncertainty and mitigates the possibility of risk such that it does not account for increased demand. Gurrea, Tr. at 1828:3–21 (explaining that utilities would likely anticipate higher storage needs to accommodate for potential inaccuracy of predicted discharges), 1829:7–12, 1833:9–14. However, the new iterative aspect of the Graves model is a direct response to the Government's prior critiques that the model was unreliable because it did not take into account what actually materialized over time. Graves, Tr. at 931:7–932:5, 957:7–24. Moreover, as Mr. Graves explained, nuclear power plants are extremely accurate about forecasting discharges, with

less than an eight-percent variance in projections. *See id.* at 2117:7–2118:6. Considering that the updates to the Graves model are responsive to the Government's prior criticisms and given the reliability and availability of SNF data, the Court see no problem with the model's use of foresight and hindsight in creating accurate projections.

c. Other Assumptions: Universal Participation and Uniform Costs

The Government also argues that the Graves model improperly assumes universal participation by utilities and uniform storage costs across sites. ECF No. 104 at 32. As to universal participation, Dr. Gurrea asserts that all utilities would not participate in exchanges as the Graves model assumes, for example, if they rely on their own OFF rights or at-reactor storage, face sociopolitical resistance, or are dissuaded by the high cost of exchanges. Gurrea, Tr. at 1809:20–1810:4, 1849:8–12. This is an oft-repeated criticism of the Graves model that courts have found does not substantially impact the conclusions of the model. *See, e.g.*, *Dairyland Power II*, 645 F.3d at 1370 (concluding that "even assuming some utilities refused to contract, 'the Government did not make any showing that this would have substantially affected Mr. Graves' . . . conclusions'" (quoting *Dairyland Power I*, 90 Fed. Cl. at 634)); *Portland Gen.*, 107 Fed. Cl. at 645 ("We find that the exchanges provision would most likely have been used by the utilities in the 'but-for' world of DOE performance to establish a market for exchanging allocations . . . [and that] all parties involved would have been willing to exchange allocations to maximize savings and efficiency."); *Pac. Gas II*, 92 Fed. Cl. at 186 ("Even if some of these utilities had decided not to participate in exchanges or [the] DOE had not been willing to approve certain proposed exchanges, [the plaintiff] more likely than not would have found a utility willing to accept [its] 1999 allocations in exchange for 1998 allocations.").

As this Court has already held, it is more likely than not that utilities would have participated in exchanges given the many efficiencies it offered as compared to fuel removal on the OFF schedule alone. Consistent with the reasoning in prior SNF cases, the Court agrees that most, if not all, utilities would have participated in exchanges to the extent it would have been economically beneficial for them. *See* Graves, Tr. at 1082:23–1083:15. Also, given the many available trading partners due to the persistent slack in the market during the claim period, it is more likely than not that Plaintiff would have found the necessary exchanges to achieve its fuel-out date such that there is no substantial impact on Mr. Graves' conclusions. Accordingly, this criticism falls flat.

As to uniform costs, Dr. Gurrea argues it is unrealistic to assume storage costs, *i.e.*, building dry storage, maintaining dry storage, and maintaining the pool, are identical across plants. Gurrea, Tr. at 1834:4–15. He contends that plant storage costs vary significantly, yet the Graves model assumes the costs are constant and uniform across the industry. *Id.* at 1834:24–1835:7, 1836:1–12. Mr. Graves responds that he used an average for all sites, which is appropriate in modeling, especially when such costs would have been unknown without hindsight. Graves, Tr. at 2114:17–2115:11. Regardless, Mr. Graves explained that those costs do not impact the model's results. *Id.* at 2115:13–2116:5. With full DOE performance and a functioning exchanges market, the need for dry storage would have been effectively eliminated. *See id.* at 932:1–10. By 2004, given the excess DOE capacity, the program would have met all the utilities' needs before any spending on maintenance or storage was required; and thus, it matters not "what it would have cost. The solution is the same." *Id.* at 1000:4–5; *see id.* at 941:4–24, 942:13–18, 999:17–25 (explaining he did not conduct sensitivities for storage costs in this case because they do not matter after the program moves into a period of slack). Given the slack in the program, the Court agrees with Mr.

Graves that the use of average costs is an adequate measure, and further that the use of uniform costs does not meaningfully alter the results of the model.

d. Optimization Model

Finally, the Government criticizes the Graves model in this case as being an optimization model that focuses on reducing at-reactor costs for utilities, and thus produces results inconsistent with individual utilities' OFF rights and prior Graves models. ECF No. 104 at 34–35. Specifically, the Government contends that the model prioritizes cost optimization without regard for an individual plant's OFF rights based on its discharges. Gurrea, Tr. at 1779:2–11 ("[T]he solution searches for what [is] the best use of the program capacity regardless of what are the individual plants' rights, and what are their participation decisions[.]"). The Government further insists that the Graves model does not later readjust the model (specifically, Module B) based on actual OFF rights. *Id.* at 1785:17–1786:3.

The Government relatedly argues that the model's results are inconsistent with prior Graves models. As it points out, in the last round of litigation, Mr. Graves opined that Plaintiff "would have been eligible for fuel removal in 2020—a difference of four years and $45 million in damages from what he offers here." ECF No. 104 at 32. In the prior round, Mr. Graves assumed fuel would be cooled five years, whereas in this round, Mr. Graves assumes DOE can accept one-year cooled fuel. *Id.* at 32 n.10. The Government highlights there are "dramatic differences in price predictions between the Graves models" such that plants for whom he offered models would have recovered much less in damages based on his current model; therefore, the Court should give no deference to this model based on prior versions. *Id.* at 23.

The general criticism that Mr. Graves' model focuses on cost minimization and thus models an ideal market is a valid one. Even Mr. Graves agrees that the model aims to minimize

costs for utilities, determining the least-cost allocation across the industry, as an efficient market would, noting further that the industry is full of cost-conscious participants. Graves, Tr. at 930:12–17, 977:21–978:9, 1014:4–7, 1053:6–17; *see also id.* at 1054:11–16 (a highly competitive market would be very efficient). But its objective has not prevented courts from accepting the model as sufficient to meet Plaintiff's burden. *See, e.g.*, *Yankee Atomic*, 679 F.3d at 1359–60. Moreover, the Government's insistence that the model produces results inconsistent with OFF rights is unfounded. As Mr. Graves explains, only Module B of his model conducts a cost-optimization and remains "unadjusted" because it has not yet been constrained by Module D to ensure that the allocated exchanges are feasible based on a plant's OFF rights. Graves, Tr. at 1066:22–1067:1; *see id.* at 1074:1–2 ("Module D then confirms whether or not that's feasible."). The model's results, filtered through all four modules, are, thus, aligned with existing OFF rights because while Module B performs a cost-optimization, the model is capped in later modules, and especially in the given market year, to physical commitments based on a utility's OFF rights. *Id.* at 961:5–962:8, 1064:9–21, 1077:13–15; *see also id.* at 2122:7–12 ("The model never forgets how much capacity you have rights to, and if you don't use it all in one period, it carries exactly that amount forward that you didn't use."). Accordingly, the Government's criticism fails.

As to the Government's argument that the current model is inconsistent with prior Graves models, the Court believes that the inquiries in prior cases were distinct, considering that short-cooled fuel was not at issue. *See NSVY*, 159 Fed. Cl. at 583–86 (rejecting the Government's judicial estoppel argument). Nevertheless, as the Court highlights in its analysis above, there are several consistencies across versions of the Graves model in terms of the reliable sources of information and economic framework employed such that prior rulings involving the Graves model inform the Court's review. As well, in the prior round, the Graves model predicted a 2020

fuel-out date, assuming fuel would be cooled at least five years, which, notably, is consistent with the Gurrea model here that also assumes fuel would be cooled at least five years. The reliability of the Graves models is thus bolstered by the consistency of its prior results with the results of the Gurrea model where both models accepted a fundamental assumption on fuel aging. As such, this criticism also fails.

C. The Gurrea Model is Unreliable.

The Government's model, on the other hand, suffers from several defects. As an initial matter, two assumptions of the Gurrea model, which were both based on the instruction of counsel, are incorrect. The first assumes that a utility can deliver only five-year cooled fuel, and the second imposes a 10-year limit on the availability of DCSs. Gurrea, Tr. at 1723:4–16, 1725:12–18; ECF No. 104 at 38 n.12.[16] In any case, the Gurrea model suffers from other defects, including a breach-infected and exaggerated view of social and political risks and other modeling features that result in unusual and illogical behavior by utility participants.

1. Overview of the Gurrea "Exchanges" Model

The Gurrea model is the first exchanges model presented by the Government in a SNF case. The model begins at the plant level with individual plants' OFF allocations based on a 10-year window of approved DCSs. Gurrea, Tr. at 1778:21–22, 1837:24–1838:1, 1911:3–6. Then, "constrained by their own DCS schedule[,]" plants decide whether to participate in exchanges each year based on the obstacles and advantages of participation, *e.g.*, social-political factors and economic incentives to avoid incremental storage costs. *Id.* at 1838:17–19; *see id.* at 1792:21–

[16] Because the Court has already held that DOE's disposal obligation applies to short-cooled fuel and that Plaintiff has met its burden of establishing that it was technically feasible for DOE to accept and dispose of short-cooled fuel on Plaintiff's proffered timeline, *see supra* § II.B, the first assumption need not be discussed further here.

1793:5. Like the Graves model, the Gurrea model assumes that plants will participate in exchanges to avoid incremental storage costs; however, it also assumes that in any market year when a plant can handle its own storage needs, the plant will not participate in exchanges that year. *Id.* at 1848:3–1849:4. For Vermont Yankee, this means that in market year 1997, looking forward for 10 years, it has "no need to participate in exchanges to avoid any incremental costs," since its OFF rights are sufficient (and given potential social-political pressures). *Id.* at 1849:20–24. Once Vermont Yankee cannot avoid storage costs using the OFF schedule, which happens after 2014, it decides to participate in the exchanges market. *Id.* at 1850:13–18.

The plants' participation decisions form the basis of the reduced supply curve in Dr. Gurrea's exchanges market, which is also constrained by social-political factors, including state, local, and stakeholder pressure to have all SNF removed from nuclear sites as soon as possible. *See id.* at 1797:21–23, 1799:10–18, 1811:20–1812:9.

Next, the Gurrea model employs "a series of sequential bilateral trades where plants engage in trades and assess the opportunity to improve [their schedules] through mutually beneficial transactions" using a Monte Carlo simulation, a statistical tool used in modeling scenarios that involve uncertainty and a range of possible values. *Id.* at 1838:22–25; *see id.* at 1721:15–1722:6. The model adopts many of Mr. Graves' input assumptions, including assumptions regarding the availability of information (like pool capacities), uniform and known on-site storage costs, and perfect foresight to project discharges. *Id.* at 1719:8–16, 1839:21–1840:3, 1841:4–16, 1841:24–1842:2. However, unlike the Graves model, the Gurrea model only simulates bilateral trades, meaning it forms specific pairings of reciprocal exchanges between utilities with approved DCS rights to trade, as opposed to what Dr. Gurrea characterizes in the Graves model as deterministic

aggregate industry estimations without regard for individual plant DCS rights or participation decisions. *Id.* at 1844:8–23.

To simulate uncertainty in the exchanges market, each participating plant engages in 12 rounds of trades each year from 1998 to 2025, which is purportedly consistent with DOE's 30-day review process for exchanges approval. *Id.* at 1843:15–1844:12, 1927:20–1928:15. The model also performs 100 simulations to assess alternative bilateral trade sequences. *Id.* at 1844:7–12, 1929:16–20. At the end of these simulations, the model selects a likely and mutually beneficial bilateral exchange that maximizes the value of the exchange and then evaluates the transaction cost of the exchanges using the Nash bargaining solution, a tool used to predict the equitable outcome of a complex negotiation. *Id.* at 1843:23–1844:3, 1845:2–22. According to Mr. Graves, only about 20 to 30 percent of trading efforts simulated in the Gurrea model result in an exchange. Graves, Tr. at 2128:24–2129:5.

Ultimately, based on his model, Dr. Gurrea opines that Vermont Yankee would have a fuel-out date of 2020, which is seven years ahead of the 2027 OFF schedule but four years behind the 2016 fuel-out date predicted by the Graves model. *See* Gurrea, Tr. at 1850:13–1851:5. Given a 2020 fuel-out date for Vermont Yankee, the Gurrea model also estimates O&M savings of $70 million and a transaction cost of $16 million to effectuate the exchanges. *Id.* at 1851:9–19.[17]

2. <u>A 10-year Limit on the Availability of DCSs Is Unsupported by the Evidence.</u>

The 10-year limit on the availability of DCSs is a constraint built into the Gurrea model at the instruction of counsel. The Government argues that the Graves model improperly fails to impose any limit on how far in advance utilities could hold approved DCSs (based on ACR and

[17] The trial transcript contains an error with respect to the amount of the cost. Dr. Gurrea identified the amount as $16 million during his testimony, not $60 million. *See* DDX 3 at 54.

APR information). ECF No. 104 at 37. According to the Government, "DOE would not have approved a DCS submitted for acceptance outside of the [10-year] horizon provided in the ACR." *Id.*; Barton, Tr. at 1229:20–1230:2. However, the 10-year ACR/DCS constraint is unsupported by the plain language of the Standard Contract, DOE statements and documents, and testimony from the Government's own witnesses.

Specifically, the Standard Contract provides:

> Beginning not later than July 1, 1987, DOE shall issue an annual capacity report for planning purposes. This report shall set forth the projected annual receiving capacity for the DOE facility(ies) and the annual acceptance ranking relating to DOE contracts for the disposal of SNF and/or HLW including, to the extent available, capacity information *for ten (10) years following the projected commencement of operation of the initial DOE facility*.

JX 1 at 10 (Art. IV.B.5(b)) (emphasis added). If DOE had not breached the contract, the initial DOE facility was projected to commence operations by no later than January 31, 1998. *Id.* at 6 (Art. II). Therefore, the first ACR was supposed to provide annual receiving capacity at the DOE facility for 1998 through 2007. *See* JX 2 at -2716. The language of the Standard Contract does not indicate that each subsequent ACR would similarly provide capacity information for the same 10-year period, or in 10-year increments, following commencement of the program. As well, nothing in the terms of the Standard Contract, including the other provisions about APRs, DCSs, or the DCS form in Appendix C, contains a 10-year limit on the availability or approval of DCSs, as both Ms. Connie Barton, the current DOE contracting officer, and Mr. Kouts admitted at trial. *See* JX 1 at 10–11, 19, 38–39; Barton, Tr. at 1310:19–1311:1, 1312:18–22, 1318:24–1319:10, 1326:21–25; Kouts, Tr. at 1467:16–20.

Moreover, the first ACR, published in 1987, stated that the ACR would be published each year through 1990, but that beginning in 1991 it would be converted into an APR. JX 2 at -2712. And the Standard Contract sets no time frame or limit for information provided in the APR.

Barton, Tr. at 1330:14–20; JX 1 at 10 (Art. IV.B.5(a)). Additionally, the 1987 ACR reiterated, as did each ACR thereafter, that the ACR "is for planning purposes only, and thus, is not contractually binding on either the DOE or the [utilities]." JX 2 at -2712; 1991 ACR at -3594–95, DX 3056. This evidence indicates that there is no contractual 10-year limit on the availability of DCSs.

Ms. Barton testified to the contrary. In sum, she stated that there is a 10-year limit on the approval of DCSs, that a utility can submit a DCS only if it has an allocation in the 10-year period following the date of its request (although, admittedly, she has never been involved in reviewing DCSs), and that DOE would not have approved any DCS request outside the 10-year horizon. Barton, Tr. at 1221:5–1222:4, 1229:20–1230:2, 1318:19–1319:4; *see, e.g.*, DX 3056 at -3600; PX 3066 at 1–2. As noted above, while certain DOE documents identify annual capacity in 10-year increments, nothing in the terms of the Standard Contract nor any DOE policy guidance, notice to utilities, or any other documentation corroborates DOE's current, arguably breach-infected position that it would not have approved any DCS approval request outside a 10-year horizon. Barton, Tr. at 1313:6–11; Kouts, Tr. at 1471:13–21; *see also Pete Vicari Gen. Contractor, Inc. v. United States*, 51 Fed. Cl. 161, 169 (2001) (extrinsic evidence cannot be used to "insert a term into a contract that simply is not there").

Conversely, DOE specifically directed utilities seeking to make planning decisions beyond the 10-year period covered in an ACR to the 1987 Mission Plan Amendment, which provided, for planning purposes, projected acceptance rates through 2038. Letter from Beth Tomasoni, DOE, to Ted Feigenbaum, N. Atl. Energy Serv. Corp. (July 14, 1993) at -1128, DX 3065; *see* DX 3025 at 60–61. This statement demonstrates that both the utilities and DOE understood the need for long-term planning and management of SNF. And, of course, the Federal Circuit has since established the annual waste acceptance rates set forth in the 1987 ACR (including the 1987

Mission Plan) as the rates used to calculate damages in SNF litigation because it was the "most accurate picture of the parties' intent . . . when both parties still anticipated timely and full performance of the contract." *Pac. Gas I*, 536 F.3d at 1291.

In support of the 10-year limit, Ms. Barton primarily relies on the 1992 DCS Instructions drafted by DOE and DOE's statement to a utility, which state that "[a] purchaser may submit DCSs for as many of their allocations as they choose*, throughout the 10 year period identified in the ACR*." Letter from M. Detmer, DOE, to J.T. Owens, Portland Gen. Elec. Co. (Mar. 4, 1992), attaching DOE Instructions for Completing the App. C DCS at -24, DX 3058 (emphasis added). Even assuming the DCS Instructions impliedly disallow DCS requests outside of the 10-year period identified in the ACR, such period would most likely be a "rolling" 10-year limit with a projected time frame that would always be at least 16 years, if not 20 years, ahead of the DCS request date. After all, under the Standard Contract, the first ACR was to be issued in 1987 projecting acceptance rates for the initial 10 years of the program (1998–2007). If the purpose of the report was to facilitate planning, it is reasonable to expect that the 1988 ACR would "roll forward" the initial 10 years (1999–2008), and so on with subsequent ACRs, meaning the period covered by the report would be 20 years ahead of the utility's discharge of fuel. Pl.'s Handwritten Demonstrative, PDX 4 (ACR & APR roll-forward visual). Alternatively, if the 10-year rolling projections began with the issuance of the 1991 ACR and/or the first APR in 1991, per the DCS Instructions, then the time frame would always be 16 years ahead of a utility's discharge of fuel. *Id.*; DX 3058 at -26 ("The DCS should be submitted by all Purchasers with allocations in the 1991 Annual Capacity Report (ACR) (*or subsequent ACRs, as appropriate*)[.]" (emphasis added)). Even the Government's own witness, Mr. Kouts, admitted that he believed the ACR would be 16 years ahead of any given year. Kouts, Tr. at 1478:11–1479:9.

Finally, accepting the Government's alleged 10-year limit would invalidate earlier versions of the Graves model presented in prior SNF cases despite the fact that the model has been widely accepted. *See, e.g.*, *Yankee Atomic*, 94 Fed. Cl at 703, 707 (finding that the Connecticut Yankee plant would have had a fuel-out date of 2001 although their OFF date was 2012). The foregoing discussion illustrates that the Government's 10-year limit is unsubstantiated, and since it is an assumption built into the Gurrea model, the model must be rejected as unreliable. Fed. R. Evid. 702(d); *see, e.g.*, *Tyger Constr. Co. v. Pensacola Constr. Co.*, 29 F.3d 137, 143 (4th Cir. 1994) (expert opinion should be excluded when it is based on a faulty assumption that is unsupported by the evidence).

3. <u>The Gurrea Model Fails on Other Grounds.</u>

In any event, the Gurrea model also fails on other grounds—namely, defects in its assessment of the sociopolitical risk for utilities participating in the exchanges market, as well as the illogical plant behaviors and outcomes resulting from the model's methodology.

a. Breach-Infected View of Sociopolitical Risk

Dr. Gurrea's testimony emphasizes the importance of sociopolitical factors in modeling an accurate exchanges market. *See* Gurrea, Tr. at 1799:19–1801:20. Without incorporating sociopolitical factors, Dr. Gurrea explains, the result is an oversimplified market with overstated supply. *Id.* at 1801:4–20. As opposed to the Graves model, Dr. Gurrea's model presumes socioeconomic and sociopolitical factors impact overall supply. *Id.* at 1797:16–23, 1846:1–1847:5 (discussing the complexity of the market and anticipating active participation by local and state-level authorities as well as other stakeholders in approving changed removal schedules, slowing down exchanges). Specifically, Dr. Gurrea posits that DOE program capacity is not the same as supply in an exchanges market, and that sociopolitical factors would constrain utility participation

in favor of earlier removal of spent nuclear fuel, resulting in a more restricted supply of exchanges. *Id.* at 1799:10–18, 1848:6–17.

Mr. Graves rebuts Dr. Gurrea's approach of dealing with sociopolitical risks. While Mr. Graves agrees that there is public anxiety surrounding nuclear fuel operations, he disagrees about how these concerns would limit exchanges. Graves, Tr. at 2110:9–14. Unlike Dr. Gurrea, Mr. Graves does not believe public anxiety would create a preference for earlier removal of fuel if there were a functioning DOE fuel removal program; rather, the public would favor fewer, more strategic campaigns for removal. *Id.* at 2110:15–2111:2. Mr. Graves thus characterizes Dr. Gurrea's approach, namely getting SNF off site as soon as possible, to be breach-world thinking. *Id.* at 2111:3–16. Mr. Graves explained that, in a non-breach world, removing SNF would be safer and simpler and by 2014, with the passage of approximately 16 years, a robust exchanges market would have developed. *Id.* at 2112:10–2113:13. Therefore, Mr. Graves opines that the sociopolitical risks that Dr. Gurrea emphasizes would result in more exchanges, not fewer. *See id.* at 2112:10–18.

The Court agrees with Mr. Graves that the Gurrea model suffers from a breach-infected view of sociopolitical risk, unduly constraining supply through limited utility participation in the exchanges market. In the but-for world, public concern over the presence of SNF at nuclear power plants would be allayed by DOE's full performance. And any fears about storage or transportation of SNF would be better solved through the use of exchanges, which the Graves model shows would collectively remove fuel from plants faster, with fewer pickups, and without the need for building interim dry storage. *Id.* at 2109:2–10. The Court is not required to accept a model purported to represent a non-breach world when it concludes that the model has been influenced by breach-world thinking. *See Pac. Gas I*, 536 F.3d at 1291 (declining to rely on DOE's tainted 1991 ACS

process, because by then DOE performance had "already become a distant possibility"). As this Court has already held, the utilities would most likely have participated in exchanges given the significant efficiencies for both DOE and utilities, as well as the cooperative nature of the nuclear industry. *See supra* § II.A; *see also Portland Gen. Elec.*, 107 Fed. Cl. at 645 (finding that political and community pressure to remove SNF as soon as possible would not outweigh desires to eliminate increased exposure to SNF through repeated shipments).

Yet, under the Gurrea model, in attempting to address sociopolitical risk, utilities with the most available supply of DCSs to exchange are prevented from participating in the market, Graves, Tr. at 2124:1–18, even though most utilities have been observed to be cooperative when there is no cost to them, Brewer, Tr. at 1640:11–1641:1; Graves, Tr. at 2143:25–2144:5. The Gurrea model's breach-infected view of sociopolitical risk based on public apprehension to DOE's failure to collect SNF is a significant defect in the model and is inconsistent with a functioning DOE program and a developed exchanges market in a non-breach world, which undermines the reliability of the model.

b. Illogical Utility Behavior and Outcomes in the Exchanges

Other assumptions and the methodology in the Gurrea model further undermine its reliability. While there are several aspects of the Gurrea model that Mr. Graves criticizes, three standout as illogical utility behaviors or unusual outcomes.

First, as briefly discussed, the Gurrea model overly constrains utility participation due to sociopolitical factors, but it also does so in a manner inconsistent with rational behavior for market participants in the exchanges. Specifically, the utilities in the Gurrea model only participate in exchanges once they are unable to manage their own storage needs, or rather, once their OFF rights are insufficient to handle their "must-move" fuel, despite significant profits, cost savings, and

efficiencies available with earlier and more strategic participation in the exchanges market. Gurrea, Tr. at 1848:20–1849:4; Graves, Tr. at 2123:5–9, 2123:21–2124:4. Referring to the constrained supply in the Gurrea model, Mr. Graves testified that "it's quite unusual to think that the parties with the most available supply wouldn't participate . . . [and] there would be fewer and fewer participants over time, even though the market, the capacity of the program is getting farther and farther ahead of total needs[.]" Graves, Tr. at 2124:8–14. The Court agrees with Mr. Graves.

It would be irrational for a utility not to participate in the exchanges market and rely only on its OFF rights when doing so means it would forego potential profits from earlier exchanges and engage in numerous inefficient pickups; yet the same utility would choose to exchange its OFF rights in later years when it has the greatest need for removal of fuel from its site, *e.g.*, due to an upcoming shutdown. *See id.* at 2144:22–2446:20. Such illogical participation decisions by utilities in the Gurrea model artificially remove the "slack" from the market such that competition for exchanges worsens and prices for exchanges increases. *Id.* at 2126:19–2127:18. These atypical market mechanics and unusual utility behaviors guarantee overpriced transaction costs for exchanges (*e.g.*, $16 million for Vermont Yankee) even in later years of the program because the market is artificially constrained and does not account for the increasing DOE program capacity or a maturing exchanges market. Gurrea, Tr. at 1851:3–19; Graves, Tr. at 2137:19–23, 2147:1–25.

Second, the Gurrea model uses randomized interactions between trading partners and simulations to account for uncertainty in the exchanges market. Gurrea, Tr. at 1843:19–1844:12. Each plant participating in exchanges engages in 12 rounds of trades a year, and the Gurrea model runs 100 simulations. *Id.* at 1844:5–12, 1927:20–1928:15. However, the mechanics of random calls between seemingly uninformed utility participants to find mutually beneficial exchanges

produces illogical and unlikely results, especially considering the vast information available regarding each utility's discharge patterns as well as the overall cooperative nature of the nuclear industry. *See* Graves, Tr. at 2128:1–19, 2130:5–15. Even more unrealistic is that the mechanics of the model do not accommodate for improved interactions between utilities, whether between rounds or based on iterative knowledge or foresight acquired over time, because all successful trades only occur randomly, whether in the first round or the eleventh round and whether in 2001 or 2014. *See id.* at 2128:16–19, 2129:2–2130:4. It is therefore unsurprising that the success rate in any given year for exchanges in the Gurrea model is only between 20 and 30 percent as each utility effectively acts as a blind or new participant in each exchange attempt. *Id.* at 2129:1–2.

Lastly, and likely an outcome of the artificial 10-year DCS limit, *see id.* at 2131:3–17, some utilities in the Gurrea model build ISFSIs requiring significant upfront investment (ranging between $10 million to $44 million) that ultimately go unused. Gurrea, Tr. at 1837:4–9; Graves, Tr. at 2109:2–14, 2130:21–2131:17. Mr. Graves estimates that this irrational behavior of unnecessary ISFSI construction occurs about 337 times in the Gurrea model, at nine different sites across 100 simulations, and at least once in every simulation. Graves, Tr. at 2131:12–15. This is a problematic and illogical outcome in the Gurrea model that confirms its unreliability. Even Dr. Gurrea admitted that building a dry storage facility at the cost of $41 million and not using it is an illogical result. Gurrea, Tr. at 1908:17–20.

Based on the foundational issues with the model, the breach-infected view of risk, and the illogical utility behaviors and outcomes, taken together, the Court finds the Gurrea model to be unreliable for its review of the issues in this case.

* * *

Accordingly, Plaintiff has established by preponderant evidence that it is entitled to recover damages for wet pool storage costs between 2017 and August 2018.

III. Additional Claimed Costs

The remaining damages sought pertain to various categories of claimed costs that Plaintiff allegedly incurred as a result of DOE's breach, including costs associated with the construction of ISFSI Pad 2 and the loading of 45 MPCs at the Vermont Yankee site following the plant's shutdown. The Court addresses each category in turn.

A. Resource Code 490 Allocations Are Recoverable.

Plaintiff seeks damages pertaining to the transfer of service company billing costs, recorded for accounting purposes under Resource Code 490, to VYNPS during the claim period. Plaintiff's parent company, Entergy Corporation, established service companies to provide shared administrative and general services as well as operating services to several other Entergy companies. Heard, Tr. at 550:19–551:1. As services are provided, the service companies bill the service costs to the Entergy affiliate company that receives the services. *Id.* At the corporate level, these service company billings are either allocated to the Entergy affiliate companies based on a historical distribution of cost drivers or billed directly to the companies. *Id.* at 551:9–552:15. At the plant level, Plaintiff allocated Resource Code 490 costs during the claim period among three project categories: license termination, spent nuclear fuel management, and ISFSI operations at VYNPS. Swigart, Tr. at 768:1–12, 788:24–789:8. Because the Vermont Yankee plant had ceased operations and entered decommissioning, these were the only projects ongoing during the claim period. *Id.* at 768:16–18. Plaintiff allocated the costs among these categories based on forecasted

spending for each category. *Id.* at 771:17–21. In total, Plaintiff is claiming $14,379,864 in damages for Resource Code 490 costs. ECF No. 81 ¶ 16(a)(i).

The Government does not dispute that allocation of costs like those captured under Resource Code 490 are generally recoverable in SNF litigation, nor does it dispute the allocation method used at the corporate level to transfer costs to VYNPS. *See* Peterson, Tr. at 2005:15–2006:5. But the Government does challenge $9,320,705 for Resource Code 490 costs that it considers to be unrecoverable. *See id.* at 2006:6–8; ECF No. 81 ¶ 16(a)(i)(1). Specifically, the Government argues that instead of using the cost drivers approved by the Federal Energy Regulatory Commission ("FERC"), which are used at the corporate level to distribute service company billings, Plaintiff created a new process to distribute the costs internally at the project level. *See* ECF No. 104 at 57–58. That methodology, according to the Government, is flawed and resulted in a disproportionate amount of service company costs being attributed to ISFSI operations. Peterson, Tr. at 2008:19–2009:8. The Government's expert, Mr. Robert Peterson,[18] offered what he believes is a reasonable allocation method applying a three-percent rate to approximate the corporate allocations driven by the dollars spent at the site for the three project categories. *Id.* at 2020:23–2023:20 (describing his regression analysis).

The Court finds that Plaintiff's Resource Code 490 allocation method is a fair and reasonable approximation of its damages. First, witnesses employed by Entergy at the corporate and plant levels testified that it was not feasible to use the same corporate-level cost driver methodology, which the Government does not challenge, to allocate costs among the project categories at VYNPS. Ms. Barbara Heard, Entergy's former manager of affiliate accounting and

[18] Mr. Peterson was qualified as an expert in cost and pricing in construction contracts and government contracts, financial analysis, and damages analysis. Peterson, Tr. at 1976:3–9.

allocations who oversaw the corporate-level service company billings, explained that the statistics used to formulate the cost drivers at the corporate level are not the same at the project level. Heard, Tr. at 548:22–549:1, 550:7–14, 560:1–8, 612:4–7. For example, cost drivers such as the number of employees and the number of computers cannot be used for project-level allocations the way they are used at the corporate level because a plant employee may work, or a computer may be used by a plant employee to perform work, on multiple projects in any given period. *Id.* at 560:14–561:10, 562:12–563:1; *see also* Swigart, Tr. at 775:20–776:10, 777:5–778:8. Creating a system to track usage of service company billing costs by project at the plant level would be prohibitively expensive, especially for a site that is shutting down. Mr. P.L. Swigart, Entergy's finance director for decommissioning, elaborated that developing such a system could easily cost Plaintiff $10 million. Swigart, Tr. at 765:7–8, 772:23–773:4, 778:9–20, 779:9–780:3. Even the Government's expert, Mr. Peterson, confirmed that he could not use the same corporate-level cost driver method to allocate costs at VYNPS with the information he reviewed for purposes of his opinion. Peterson, Tr. at 2087:24–2088:4.

Second, Plaintiff's allocation method is consistent with regulatory requirements and was internally vetted. Mr. Swigart testified that "to understand how costs should be categorized" Plaintiff used NRC requirements to identify the expenses that should be allocated to license termination, spent fuel management, and the ISFSI project, respectively. Swigart, Tr. at 797:7–798:16; *see id.* at 769:18–21. The allocation method was developed in consultation with Ms. Heard's team at Entergy, went through various corporate review processes, and was determined to be consistent with Generally Accepted Accounting Principles ("GAAP") and FERC requirements. *Id.* at 770:11–20, 771:6–16, 772:2–6, 782:2–7, 782:15–19. Mr. Swigart testified about contemporaneous oversight efforts to ensure accurate allocations, including quarterly reviews to

"true-up" the forecasted spending with the actual spending for each category. *Id.* at 771:22–772:1, 780:25–781:5. Mr. Swigart further explained that the forecasted spending allocation methodology is consistent with other allocation methods employed at Entergy, such as for capital suspense costs and certain overhead accounts, and the methodology has since been implemented at all of Entergy's shutdown nuclear plants. *Id.* at 783:2–17. While he disagreed with the methodology, Mr. Peterson testified that Plaintiff's overall forecasted costs used for the allocation were close to the overall actual costs. Peterson, Tr. at 2017:14–2018:1.

The Federal Circuit has repeatedly approved the award of allocated costs based on a forecasted spending methodology in SNF cases, including with respect to Entergy's capital suspense loader. *See Consol. Edison Co. of N.Y., Inc. v. Entergy Nuclear Indian Point 2, LLC*, 676 F.3d 1331, 1340 (Fed. Cir. 2012) (reversing trial court's denial of capital suspense loader costs where methodology allocated capital suspense loader cost pool to capital projects); *Vt. Yankee*, 683 F.3d at 1351 (same); *Sys. Fuels, Inc. v. United States*, 457 F. App'x 930, 936 (Fed. Cir. 2012) (same); *Sys. Fuels, Inc. v. United States*, 666 F.3d 1306, 1312 (Fed. Cir. 2012) (same); *Carolina Power & Light Co. v. United States*, 573 F.3d 1271, 1277 (Fed. Cir. 2009) (affirming trial court's award of overhead costs and other indirect expenses). Moreover, courts have found that similar evidence supporting allocated costs was sufficient to meet the plaintiff's burden of establishing damages with reasonable certainty, notwithstanding the Government's argument that the methodology was imprecise. *See Kan. Gas & Elec. Co. v. United States*, 685 F.3d 1361, 1370 (Fed. Cir. 2012) (finding that the trial court erred by denying plaintiff's overhead damages where plaintiff's "allocation rates were re-examined on a regular basis in order to reflect actual capital project costs, and the total-cost allocation method complied with required FERC accounting regulations"); *see also Wis. Elec. Power Co. v. United States*, 90 Fed. Cl. 714, 791 (2009).

The Government's challenge to Plaintiff's allocation is unavailing. As a factual matter, for the largest cost driver—the Holtec contract costs associated with the ISFSI—the Government's expert underestimates the service company costs dedicated to the dry storage project. The Government contends that compared to license termination, the ISFSI operations did not consume as much service company support because the ISFSI project was largely accomplished through contractors who rely on their own payroll, information technology, and human resources services. ECF No. 104 at 58–59. But Mr. Swigart testified that the Holtec contract needed an "extensive amount of shared service support," including supply chain, regulatory, finance, tax, environmental, legal, project management, and accounting support. Swigart, Tr. at 785:17–787:12. Mr. Kenneth Swanger, the former dry fuel storage manager at Vermont Yankee, also testified that the Holtec contract needed oversight and reporting mechanisms that included interfacing with senior management. Swanger, Tr. at 42:21–43:10, 78:22–79:10.

Mr. Peterson acknowledged that Entergy service companies likely would have provided some support to the ISFSI project; however, he suspected that the level of support would be at varying degrees and not based on the dollars spent. Peterson, Tr. at 2009:9–2010:15, 2012:1–13, 2085:12–15. According to Mr. Peterson, there should have been a more principled way of determining what service company billing costs benefitted each project category. *Id.* at 2008:23–2009:8. That there may be an arguably more precise way of allocating costs among projects, however, does not bar recovery when Plaintiff's allocation methodology is nonetheless reasonable. *See Energy Nw.*, 641 F.3d at 1309 ("Determining the amount of damages to award is not an exact science[.]"); *San Carlos Irrigation & Drainage*, 111 F.3d at 1563 ("[W]here responsibility for damages is clear, it is not essential that the amount thereof be ascertainable with absolute exactness or mathematical precision[.]" (internal quotation marks omitted)). In the circumstances at bar,

where (1) Plaintiff sought to contemporaneously allocate service company billing costs at the plant level; (2) it was impractical to use the same corporate-level cost drivers; and (3) the plant-level methodology developed was vetted, periodically reviewed, and compliant with GAAP and FERC requirements, the facts and precedent support the conclusion that Plaintiff has met its burden to prove damages.

For these reasons, the Court finds that Plaintiff has established its Resource Code 490 costs, and they are recoverable in full.

B. Materials Loader Impairment Adjustments Are Recoverable.

Plaintiff also seeks recovery of materials loader costs, which are overhead costs related to the materials management process. Curran, Tr. at 823:21–824:12. As Ms. Penny Curran, Entergy's senior manager of accounts payable, testified, these costs are added through the application of a materials loader rate that is based on a ratio of the overhead costs (FERC account 163) to the materials inventory (FERC account 154) at a particular plant. *Id.* at 821:21–22, 828:5–829:7. When a plant issues material to a project, the materials loader rate in the system at that time is applied to the cost of that item and recorded to the project. *Id.* at 824:3–12, 862:5–10. Materials loader rates are applied to both materials that go through a plant's warehouse (inventory) and materials that do not go through the warehouse, such as direct purchases from third parties, including contract purchases. *Id.* at 827:1–9.

The shutdown of VYNPS triggered an impairment analysis of the plant's assets for accounting purposes pursuant to GAAP. *Id.* at 833:11–21. As a result, Plaintiff concluded that the plant's inventory had no realizable value, and it thus wrote down accounts 163 and 154 to zero at the end of July 2013. *Id.* at 833:24–834:18, 835:18–22, 836:9–19. The write-down affected the materials loader rates at VYNPS, even though it had nothing to do with the costs associated with

the written-down assets or the management of those assets. *Id.* at 836:2–8, 837:5–16. After the write-down, accounts 163 and 154 began accumulating costs again, resulting in a materials loader rate that would attach to materials issued post-impairment. *Id.* at 836:20–25; *see* Peterson, Tr. at 2040:4–25. To calculate its materials loader costs for its damages claim, Plaintiff adjusted the materials loader rates by removing the effect of the impairment in order to reflect the actual costs consistent with Plaintiff's accounting practices. Curran, Tr. at 842:16–843:17.

The Government challenges $2,782,011 associated with Plaintiff's claim for materials loader impairment adjustments. ECF No. 81 ¶ 16(b)(ii). Specifically, it takes issue with including the costs attributable to the reversal of the impairment for the materials loader rate applied to direct purchases (*i.e.*, contract purchases) after the impairment. ECF No. 104 at 61 n.25. The Government argues that Plaintiff's adjusted materials loader rates are artificially inflated, created solely for litigation, and were not used for other projects at the Vermont Yankee site. *Id.* at 61 (citing Peterson, Tr. at 2041:14–25). As the Government's expert, Mr. Peterson, testified, the bulk of the materials issued to projects at VYNPS during the claim period related to the "turnkey" Holtec contract. Peterson, Tr. at 2042:19–24. By reversing the impairment to include overhead costs incurred prior to the write-down, which had been zeroed out against the materials on hand at the time of the shutdown, and applying that adjusted rate to materials purchased after the impairment, Mr. Peterson calculated the claim value to be about five times higher than it would have been if Plaintiff applied the materials loader rate in effect at the time the post-impairment materials were purchased. *Id.* at 2044:12–21.

The Court finds that Plaintiff presented sufficient evidence to support a fair and reasonable approximation of its materials loader costs. Consistent with GAAP, Plaintiff performed the impairment write-down at VYNPS for accounting purposes only due to the shutdown and the

effect it had on the value of the plant's assets. The impairment had no effect on the actual overhead costs Plaintiff had incurred with respect to materials management. Because the impairment was undertaken for an unrelated accounting purpose and did not reflect Plaintiff's normal cost allocation practices, the Court finds that the adjustments made by Plaintiff to reflect its actual costs were appropriate to show the full measure of damages. Indeed, in calculating his deduction to damages, the Government's expert applied the same unimpaired materials loader rates to materials that went through the warehouse during the claim period. *See id.* at 2095:2–21.

The Court does not agree that treating contract purchases differently by applying the contemporaneous post-impairment rates is reasonable. *See id.* at 2096:11–2097:10. It is true that materials that did not go through the warehouse likely did not use the overhead costs to the same degree as those that did. *See id.* at 2047:24–2048:6. However, Ms. Curran testified that the materials purchased for the dry storage project, even though they did not go through the warehouse, also consumed materials management resources. Curran, Tr. at 824:16–825:5. This would include costs "incurred for the contract setup, contract negotiation, [and] using the materials management systems." *Id.* at 831:6–12. Acknowledging that contract purchases do not benefit from all the materials management services, Ms. Curran testified that the materials assigned to the dry storage project at Vermont Yankee that did not go through the warehouse received a 75 percent discounted materials loader rate. *Id.* at 827:1–25, 842:9–15. That Plaintiff's adjustment effectively assigned costs incurred prior to the impairment to materials obtained after the impairment is of no moment. Mr. Peterson agreed with Ms. Curran that overhead costs associated with materials management do not generally match up to individual materials. Peterson, Tr. at 2036:24–2037:2. Consistent with Entergy policy, the account 163 balance is merely a value that is kept in reasonable proportion to the inventory value reflected in account 154. Curran, Tr. at 828:22–829:7. Similar costs have

been awarded in other SNF cases. *See Entergy Gulf States, Inc. v. United States*, 125 Fed. Cl. 678, 706–07 (2016) (awarding materials loader costs where the materials did not go through the warehouse).

Accordingly, the Court finds that Plaintiff has established the claimed damages for the materials loader impairment adjustment, and they are recoverable in full.

C. Plaintiff's Tax Payments Are Recoverable in Part.

The next category of damages relates to tax payments. Before VYNPS ceased operations, Plaintiff paid about $14 million per year in state and local taxes, including a generation tax to the State of Vermont based on the amount of electricity produced and a property tax to the Town of Vernon known as a municipal services tax. Gruntz, Tr. at 615:14–616:12. Due to the shutdown and the corresponding decrease in the plant's property value, Plaintiff negotiated with the Town and agreed to a property valuation of $78 million for tax fiscal years 2016 through 2021. *Id.* at 616:13–617:8, 621:20–622:3; Tax Stabilization Contract ¶ 2.01, JX 12. The Town agreed to use the same value for purposes of billing Plaintiff for the state education tax, from which it was no longer exempt once it stopped producing electricity. JX 12 ¶ 3.03; Gruntz, Tr. at 616:22–617:3. As part of the agreement, Plaintiff negotiated specific annual tax payments to the Town in lieu of the municipal services tax. Gruntz, Tr. at 620:12–621:11; JX 12 ¶ 3.01. The tax agreement assigned the entire $78 million site value to the ISFSI as the only asset of value left at the site. Gruntz, Tr. at 624:19–625:4; JX 12 ¶ 1.02(iv).

The Government objects to Plaintiff recovering the $4,002,971 in tax payments Plaintiff made to the Town of Vernon and the State of Vermont during the claim period. ECF No. 81 ¶ 16(c)(i); ECF No. 104 at 47. It argues that Plaintiff failed to model a plausible non-breach world depicting its tax liability following the plant's shutdown. ECF No. 104 at 47. Specifically, the

Government contends Plaintiff's model of the non-breach world is incomplete because it only accounts for $10 million in land value from the Town's appraisal report and fails to account for remaining assets that would be on the site, including the spent fuel pool. *Id.* at 50–51. Further, it ignores that Plaintiff would similarly have negotiated with the Town to reach a property valuation consistent with the same negotiation objectives and motivations; in other words, Plaintiff has not shown how a similar agreement in the non-breach world would have been any different. *Id.* The Government also argues that DOE could not have foreseen that a tax agreement between Plaintiff and the Town would be negotiated in a way to attribute the entirety of the $78 million valuation of the site to the ISFSI as the only asset with taxable value regardless of its individual value. *Id.* at 54–55.

The Court finds that Plaintiff is generally entitled to damages for taxes paid. First, the type of cost—tax payments—is foreseeable. The Government concedes as much. *Id.* at 53. That the parties reached an agreement to determine Plaintiff's tax liability does not warrant a contrary conclusion. *See SMUD I*, 293 F. App'x at 771 ("[T]he foreseeability prong applies to the type of loss, not the means of mitigation."); *Citizens Fed. Bank*, 474 F.3d at 1321. As Mr. Cory Gruntz, Entergy's senior tax manager, testified, prior to the shutdown Plaintiff had similarly negotiated annual agreements with the Town to establish the value of the Vermont Yankee site for tax assessment purposes. Gruntz, Tr. at 614:3–4, 615:11–22. The same occurred during the claim period, except that the then-recent shutdown of the plant had a significant effect on the property value. By Mr. Gruntz's account, the post-shutdown negotiations proceeded in the normal course. *See id.* at 617:4–21 (describing negotiations). According to Mr. Gruntz, it was the Town's objective to assess a large value for the remaining SNF onsite, which was the only asset of value left, and Plaintiff's objective was to minimize its tax cost and avoid litigation with the Town. *Id.*

at 617:24–618:2, 618:13–24. Whether the final tax agreement attributed the value of the site to the ISFSI alone (or in some other manner) does not call into question the foreseeability of Plaintiff's tax liability.

Second, any risk of uncertainty caused by the inability to model Plaintiff's tax liability in the non-breach world is assumed by the Government. *See Locke v. United States*, 151 Ct. Cl. 262, 267 (1960). It may be true that the parties would have similarly been interested in reaching an agreement on an assessed value for tax purposes, and that their respective objectives and motivations would have been the same. But it is simply impossible to know what a hypothetical negotiation between Plaintiff and the Town would have yielded, and this impossibility is because of the breach. The Government cannot insist on proof "which by reason of [its] breach is unobtainable." *Id.*; *see S. Cal. Edison*, 93 Fed. Cl. at 355 ("[A]ny risk of uncertainty is assumed by the party whose wrongful conduct caused the damages."); *LaSalle Talman Bank, F.S.B. v. United States*, 317 F.3d 1363, 1374 (Fed. Cir. 2003) ("[W]hen damages are hard to estimate, the burden of imprecision does not fall on the innocent party."). What Plaintiff has established is that, had DOE fully performed, all SNF would have been removed from Vermont Yankee by the end of 2016, leaving no assets of any value onsite. Since the ISFSI remained after the shutdown, Plaintiff incurred liability for taxes based on the assessed value of the property that it otherwise would not have incurred but for the breach.

Finally, Plaintiff reasonably excluded from its claim the taxes attributable to the value of the land ($10 million), which it would have incurred regardless of the breach. *See* Property Tax Based on Land Value Only, PX 3238; Gruntz, Tr. at 625:21–627:22; *see also* Appraisal Report of the Vt. Yankee Nuclear Station (Apr. 1, 2016) at 24, PX 3131. The Court agrees, however, that additional amounts should be excluded from Plaintiff's damages claim with respect to taxes. The

first relates to a portion of the tax payments for tax fiscal year 2018–2019. The claim period at issue in this matter ends on December 31, 2018. ECF No. 102 at 8. To the extent a portion of the tax payments made for 2018–2019 relate to Plaintiff's tax liability in calendar year 2019, they are beyond the scope of this case and should be sought, if appropriate, in the next round of litigation. Mr. Peterson quantified this adjustment for calendar year 2019 at $58,598. Peterson, Tr. at 2061:1–10 (discussing DDX 4 at 35). Plaintiff does not dispute the amount, and so the Court accepts the adjustment.

The second exclusion relates to the value attributed to the spent fuel pool at the time of the agreement between the Town and Plaintiff. As the Government correctly argues, the pool would have been operational in the non-breach world as of April 2016, even under the Graves model, but the value was not excluded from Plaintiff's breach-world calculation. *See* ECF No. 104 at 50. The material facts are as follows. Plaintiff and the Town agreed to a property valuation of $78 million for the Vermont Yankee site and attributed that entire value to the ISFSI. *See* JX 12 ¶¶ 1.02(iv), 2.01. Mr. Gruntz testified that the Town assigned all the negotiated value of the site to the ISFSI because "[t]hat's the only thing that [the Town] saw with value left at the site." Gruntz, Tr. at 625:3–4; *see id.* at 672:7–10. The agreement went into effect on April 1, 2016, with an invoice date of August 2016 for the first payment. *Id.* at 620:5–7; ATPR Invoice Report, DX 3277. After the agreement, the Town's appraiser issued a report valuing the property as of April 1, 2016, using a cost approach methodology. PX 3131 at 23–24; Gruntz, Tr. at 655:17–25. Mr. Gruntz testified that the Town used the appraiser's report to justify the overall negotiated valuation. Gruntz, Tr. at 669:15–17. The appraiser assigned a value of $25.2 million to the ISFSI based on the 13 casks onsite at that time. PX 3131 at 24. The appraiser also assigned a value of $43.2 million to the

spent fuel pool because it was still being used for wet storage. *Id.* The remaining $10 million was assessed to the land and land rights value. *Id.*

It is clear then that the pool—which would have been operating at the time regardless of DOE's breach—justified a significant portion of the property's valuation as of April 1, 2016. That the Town was intent on assigning all the value to the plant's remaining assets to the one group of structures that would remain onsite for the indefinite future is understandable, considering their desire to protect the Town's tax revenue stream, but it is nonetheless a construct of the agreement and should not result in a windfall for Plaintiff. *See Bluebonnet Sav. Bank*, 339 F.3d at 1345. Accordingly, the Court finds that the Government has justified a deduction of $1,491,134 from Plaintiff's recovery of tax payments. *See* Peterson, Tr. at 2061:1–10 (discussing DDX 4 at 35).

For these reasons, the Court finds that Plaintiff has established its claimed damages for tax payments, subject to certain adjustments related to the scope of the claim period and the value assigned to the spent fuel pool.

D. Allocated Pre-2017 Site Security Costs Are Not Recoverable.

Plaintiff also seeks $10,174,167 in damages for site security costs allocated to the ISFSI project following the plant's shutdown. While Vermont Yankee was operating, it recorded security costs as general site O&M. *Id.* at 2062:21–2063:3. As a result of the shutdown, Plaintiff began allocating its security costs (just as it did Resource Code 490 costs) among three projects: license termination, spent fuel management, and ISFSI operations. Ryan, Tr. at 679:5–12; Swigart, Tr. at 767:4–9. Plaintiff chose to allocate, instead of directly charging, the costs to these three categories because the security staff supported all three projects all the time and it would be infeasible to track the staff's time per project. Ryan, Tr. at 679:20–680:6. Mr. Patrick Ryan, Plaintiff's security manager, was tasked with developing the allocation method based on his

knowledge of staffing levels and NRC security requirements. *Id.* at 677:3–6, 679:13–19, 682:13–685:12; Swigart, Tr. at 790:22–791:2. He worked with his senior security coordinator to document the allocation in a memorandum referred to as "the White Paper." Ryan, Tr. at 681:20–682:2, 715:23–716:4; *see* Memo. from Brian K. Copperthite to P.L. Swigart (Nov. 7, 2014), JX 10.

Mr. Ryan described the allocation method as follows. For the ISFSI and license termination projects, Mr. Ryan determined the minimum number of security staff necessary to comply with the NRC requirements for each project. Ryan, Tr. at 684:24–685:7; JX 10 at 2–3. He allocated the remainder to the spent fuel pool. *Id.* To calculate the minimum staff for the ISFSI, the White Paper assumed that "[i]f all Special Nuclear Material was on the ISFSI Pad today with the current configuration of the [Protected Area,] it would take 48 Security Personnel to protect the ISFSI Pad" in compliance with NRC requirements. JX 10 at 2. The allocation was then applied to three phases. Phase one contemplated the period when all SNF had been offloaded from the reactor to the spent fuel pool. Ryan, Tr. at 683:2–6; JX 10 at 2–3. In phase two, the ISFSI would be under construction and the transfer to dry storage would begin. Ryan, Tr. at 683:6–7; JX 10 at 3. Phase three would start when the transfer to dry storage was complete and the Protected Area reconfigured. Ryan, Tr. at 683:7–10; JX 10 at 3. As Vermont Yankee moved through the phases, the total number of security staff would decrease. JX 10 at 5; Ryan, Tr. at 687:12–22. Individually, however, the staff for license termination would remain constant and the staff for ISFSI operations would increase to support ISFSI construction activities. JX 10 at 5; Ryan, Tr. at 687:23–688:16. Mr. Ryan explained that he and his security coordinator developed the allocation methodology this way because they believed it was reasonable given the circumstances. Ryan, Tr. at 685:8–12.

When the White Paper was created in 2014, the Protected Area at Vermont Yankee consisted of both the ISFSI pad and the spent fuel pool. *Id.* at 720:18–22. Indeed, the White Paper itself stated that all SNF was not expected to be on the ISFSI pad until 2020. *See* JX 10 at 3 ("Third Phase ISFSI expenditures starting in 2020 (all fuel is on the ISFSI Pad) and new Protected Area established[.]"). Mr. Ryan admitted that if all SNF were in the pool during the claim period, Vermont Yankee would still be required by NRC regulations to have 48 security personnel to protect the fuel, and indeed at least one additional personnel. Ryan, Tr. at 720:23–721:13. In fact, when the first ISFSI was built, Vermont Yankee was not required to modify its security plan other than implementing minor defensive strategy changes. *Id.* at 701:4–702:18. In sum, since all SNF was stored in the existing Protected Area, the minimum requirements were not driven by the exact location of the fuel—*i.e.*, whether in the ISFSI versus the pool. *Id.* at 720:13–17.

The Government challenges the full amount of allocated pre-2017 site security costs claimed by Plaintiff. ECF No. 81 ¶¶ 16(d)–(e); ECF No. 104 at 43. It argues that Plaintiff has not demonstrated causation because the site security costs are unrelated to, and would have been incurred regardless of, DOE's breach. ECF No. 104 at 43, 45–46. Specifically, the Government notes that the regulatory security requirements are the same in the breach and non-breach worlds due to the fact that the SNF is in the Protected Area in both worlds. *Id.* at 44. Thus, regardless of whether the fuel was in both the pool and ISFSI, as it was in the breach world, or only in the pool, as it would be in the non-breach world, the costs to secure the site would be the same because Plaintiff would still need the same minimum number of security officers to comply with NRC requirements. *Id.* at 43–44. Furthermore, the Government argues that Plaintiff's security cost allocation is based on the faulty assumption that all SNF was on the ISFSI pad in 2014, which was not the case in either the breach or non-breach world. *Id.* at 45.

Plaintiff responds that it does not need to show that an overhead pool became incrementally larger due to a project undertaken because of DOE's breach in order to recover costs that are reasonably allocated to that project. ECF No. 105 at 36–37. According to Plaintiff, the only material question is whether Plaintiff's allocation in the non-breach world was reasonable. ECF No. 102 at 63. It asserts that Plaintiff's allocation method, documented in the White Paper, reasonably allocated security costs to license termination, spent fuel management, and ISFSI operations consistent with both GAAP and FERC requirements. *Id.* at 62–63. Plaintiff does not dispute that the White Paper's assumptions do not conform with Plaintiff's model of the non-breach world, but it argues that the allocation is reasonable nonetheless. ECF No. 105 at 35–36.

As an initial matter, the Court rejects the Government's argument that Plaintiff must show a difference in security costs in the breach world compared to the non-breach world to recover the allocated costs. *See Energy Nw.*, 641 F.3d at 1308 (rejecting similar argument that plaintiff's overhead costs were improperly awarded because plaintiff "did not offer proof that its overhead costs actually increased as a result of the breach"); *Boston Edison Co. v. United States*, 658 F.3d 1361, 1370 (Fed. Cir. 2011). Here, the ISFSI is the mitigation activity at issue, and it exists because of DOE's breach. Plaintiff can thus recover both the direct and indirect costs associated with the ISFSI project. *See Energy Nw.*, 641 F.3d at 1309. At trial, Mr. Ryan testified that the ISFSI required security services during the claim period consistent with NRC regulations. Ryan, Tr. at 678:11–20. Mr. Ryan stated that in addition to other duties, the security staff were assigned to provide security to the ISFSI. *Id.* at 679:20–680:6. Therefore, just as it was not required in *Energy Northwest* and *Boston Edison*, Plaintiff is not required to show that there would be an increase in security costs as a result of the breach.

The Court, however, finds that Plaintiff has failed to present sufficient facts to conclude that the allocation of security costs was reasonable. Two facts drive this conclusion. First, the allocation methodology assigns the minimum number of security staff to the ISFSI based on a false assumption that all SNF was then in the ISFSI. JX 10 at 2. There is no dispute that this was not the case in either the real-world or the but-for world. At the time the White Paper was created, Vermont Yankee's SNF was being stored on ISFSI Pad 1 and in the spent fuel pool and Plaintiff did not anticipate completing the transfer of all fuel to dry storage until 2020 after it constructed ISFSI Pad 2. What is more, while the Court can understand the rationale of basing the allocation on the minimum regulatory requirements for security, Mr. Ryan never explained (apart from the faulty assumption) why a fair allocation would assign the *entire* minimum requirement to the ISFSI project alone. The same minimum would have been required no matter which storage method was being used because the existing Protected Area contained both the ISFSI and the pool. Ryan, Tr. at 720:13–17. Moreover, most of the fuel was in the pool and the reactor (not the ISFSI) at the time the White Paper was created. Although Mr. Ryan acknowledged that the configuration of the Protected Area was the driving factor of the minimum security requirement, he did not reconcile it with the allocation methodology. *Id.* at 687:12–688:6, 719:18–720:17. In the absence of any credible explanation, the Court finds Mr. Ryan's testimony on the reasonableness of the allocation methodology and whether it represents the ISFSI's fair share of the security costs unpersuasive.

Accordingly, Plaintiff has not met its burden to show entitlement to damages for its pre-2017 security costs.

E. Most of the Claimed Costs Associated with ISFSI Cask Loading Are Recoverable.

Plaintiff next seeks damages for various costs associated with loading SNF into dry storage during the claim period. This includes costs for damaged fuel containers, damaged fuel bundles,

CILC channeling, a spent fuel pool filtration and demineralizer system, repairing and maintaining certain cranes, and maintaining and inspecting cameras. Most, but not all, of these costs are recoverable.

Damaged Fuel Containers. The COC for the Holtec dry storage system at the Vermont Yankee site requires spent fuel assemblies classified as "damaged" to be enclosed in damaged fuel containers. Supko, Tr. at 394:5–19. Plaintiff seeks recovery of the costs of purchasing 160 damaged fuel containers from Holtec in order to load damaged fuel assemblies into dry storage. *Id.* at 465:21–466:2; Swanger, Tr. at 105:23–106:6, 107:1–6. Plaintiff argues that because the damaged fuel containers were purchased for loading, the $3,333,462 cost associated with the containers is unequivocally recoverable under *System Fuels, Inc. v. United States*, 818 F.3d 1302, 1307 (Fed. Cir. 2016). *See* ECF No. 102 at 67–68. The Government argues that these costs are unrecoverable because, under the Standard Contract, utilities are responsible for supplying damaged fuel containers for transportation by DOE. ECF No. 104 at 72 (citing JX 1 at 9 (Art. IV.B.2.(a))). Additionally, Mr. Brewer testified that because repackaging damaged fuel could further damage the assemblies, and because the Holtec damaged fuel containers are prevalent in the market, it would be rational for DOE to accept them for transportation when it eventually performs. Brewer, Tr. at 1614:4–1615:5. Thus, the Government argues, Plaintiff would have incurred the cost of the damaged fuel containers in the non-breach world, and Plaintiff will not incur these costs again when DOE picks up SNF at VYNPS. ECF No. 104 at 72–73.

The Federal Circuit held in *System Fuels* that utilities are entitled to recover all costs associated with loading SNF into storage casks. 818 F.3d at 1306–07. As the Court noted, absent a contract amendment, the storage casks used by the utilities cannot also be used for transportation under the Standard Contract. *Id.* at 1306. Thus, the Court found that "under the Standard

Contracts, [the utilities] will be required, if and when the government begins to comply, . . . to unload the spent nuclear fuel from these storage casks and reload it into suitable transportation casks provided by the government." *Id.* at 1307. While the utilities will be required to incur loading costs for transportation in the case of future performance by DOE, the Court found those future costs irrelevant for purposes of recovering loading costs for storage. *Id.* at 1306–07 ("[T]he costs of loading future transportation casks, or the difference between the costs of loading these storage casks and loading transportation casks, are irrelevant to System Fuels' entitlement to the expenses it incurred for loading these *storage* casks." (emphasis in original)). The present day costs associated with loading for storage were caused by the Government's breach and were thus recoverable. *Id.* at 1307.

The facts of *System Fuels* closely parallel those here. Unless the Standard Contract is amended to allow DOE to accept the Holtec damaged fuel containers, Plaintiff will be responsible for the cost of unloading and repackaging the damaged fuel into DOE-compatible transportation casks when DOE performs. Supko, Tr. at 396:21–397:22; Barton, Tr. at 1303:13–1304:6. The Government argues that DOE may amend the Standard Contract to accept Holtec damaged fuel containers for transportation, but the Federal Circuit rejected that same argument as overly speculative in *System Fuels*. 818 F.3d at 1307. As *System Fuels* instructs, the Court concludes that the costs of purchasing the 160 damaged fuel containers for dry storage were directly attributable to DOE's breach and are thus recoverable by Plaintiff.

Camera Maintenance and Inspection. For the same reason, Plaintiff is entitled to recover the $165,787 in costs incurred during the claim period for the inspection and maintenance of a camera mounted on the spent fuel handling machine mast and of two underwater cameras in the spent fuel pool. The cameras were used exclusively for loading casks for dry storage during the

claim period. Swanger, Tr. at 110:12–111:16. They required maintenance to support the dry storage loading campaign, as the radiation and water easily lead to them burning out or needing replacement. *Id.* at 111:7–12.

Mr. Brewer testified that the camera maintenance and inspection costs would have been incurred even if the Government had performed, as the cameras would have been used for regular plant operations, such as channeling, loading casks for transportation, cleanup of the spent fuel pool, and decommissioning. Brewer, Tr. at 1590:2–1591:11. But Mr. Brewer also admitted that Vermont Yankee will need to use cameras again when DOE performs and that even if it can use the same cameras for other activities at the plant the lifespan of the equipment is short. *Id.* at 1668:7–23, 1669:1–15. Thus, Plaintiff will likely have to purchase cameras or reuse its cameras for any future decommissioning or loading activities should DOE perform, requiring it to conduct further maintenance and inspection.

Since the camera inspection and maintenance costs Plaintiff seeks were incurred for dry storage loading and will have to be incurred again when DOE performs, they are recoverable. *See Sys. Fuels*, 818 F.3d at 1307.

Crane Repair and Maintenance Costs. A similar analysis is applicable to Plaintiff's claim for $123,751 in costs incurred to inspect and maintain a reactor building crane and a spent fuel handling machine crane. The cranes were used exclusively to load dry casks for storage during the claim period, and maintenance was performed to ensure the cranes would function properly. *See* Swanger, Tr. at 60:14–17, 109:13–25. Citing to Mr. Brewer's testimony, the Government argues that maintenance and inspection would have been necessary regardless of the Government's breach, as the cranes would have been used for regular plant operations and decommissioning. ECF No. 104 at 77 (citing Brewer, Tr. at 1584:6–1586:22, 1593:17–1597:19). Even so, Mr.

Swanger testified that Vermont Yankee will need to use some crane to load casks for transportation when DOE performs, and the same maintenance and inspection costs will be incurred at that time. Swanger, Tr. at 110:1–11. Since the crane repair and maintenance efforts were directly incurred to load SNF for dry storage and will have to be incurred again when DOE performs, the costs are recoverable under *System Fuels*. *See* 818 F.3d at 1307.

CILC Channeling. Plaintiff, however, misapplies *System Fuels* as related to its claim for CILC channeling costs. Two hundred and ninety assemblies at the Vermont Yankee site were susceptible to a phenomenon known as CILC. Supko, Tr. at 390:18–20. CILC occurs when corrosive mineral deposits form on the surface of a fuel assembly's cladding, causing swelling of SNF pellets inside the cladding that can rupture. *Id.* at 390:2–14. Normally, CILC-affected assemblies must be placed into damaged fuel containers before loading into dry storage. *Id.* at 391:5–11. However, if a utility undertakes an activity referred to as "channeling," where it covers CILC-susceptible assemblies with metal sheaths known as channels, then the channeled assemblies may be handled by normal means under the Holtec HI-STORM COC, thus obviating the need for damaged fuel containers. *Id.* at 390:21–391:4. For Plaintiff's 290 assemblies susceptible to CILC, it undertook the channeling process. *Id.* at 391:22–392:1. It reasonably chose that option over the use of damaged fuel containers because channeling is significantly cheaper. Brewer, Tr. at 1579:18–22.

Plaintiff argues that had DOE performed, Plaintiff would not have had to incur the $364,721 in costs for CILC channeling, nor would it have needed to purchase damaged fuel bundles for the CILC-susceptible assemblies. ECF No. 102 at 73–74. Ms. Supko testified that by installing end caps to the cells of transportation casks that confine the fuel assemblies during transport, CILC-susceptible assemblies may be placed in transportation casks without the use of

CILC channeling or damaged fuel bundles. Supko, Tr. at 392:2–19. Ms. Supko further testified that the NRC has certified a transportation cask that is compatible with end cap technology, and she opined that DOE could have amended its transportation cask license to employ end cap technology. *Id.* at 393:2–13, 393:20–394:4. Thus, Plaintiff argues, had DOE performed, it likely would have allowed for the use of end caps, obviating the need to engage in CILC channeling. ECF No. 102 at 74.

The Government argues that it is speculative that end cap technology could be employed, and even assuming it could, Plaintiff has not provided an offset for the cost of installing end caps. ECF No. 104 at 75. As Mr. Brewer testified, Plaintiff is only seeking the costs of installing the channels—not the actual channels themselves—and Plaintiff would have likewise incurred costs to install end caps, even assuming DOE would have received approval for casks that are compatible with end cap technology. Brewer, Tr. at 1580:4–1581:8. Thus, the Government contends, Plaintiff has not demonstrated the extent, if any, to which the Government's breach caused the costs associated with CILC channeling. ECF No. 104 at 75–76.

Plaintiff did not rebut Mr. Brewer's testimony that there would be costs involved with installing end caps, and Plaintiff has not provided an offset of those costs, which is its burden. *Energy Nw.*, 641 F.3d at 1306 ("a plaintiff must prove the extent to which his incurred costs differ from the costs he would have incurred in the non-breach world"). Instead, Plaintiff argues that it need not rebut Mr. Brewer's testimony, because under *System Fuels* it is entitled to all costs associated with loading for dry storage. ECF No. 105 at 45 (citing *Sys. Fuels*, 818 F.3d at 1306). The material question under *System Fuels*, however, "is not whether some process is necessary for cask loading," it "is whether some process was made necessary by DOE's breach." *Entergy Nuclear Indian Point 2 v. United States*, 128 Fed. Cl. 526, 544 (2016) (rejecting the argument "that

since in *System Fuels* the Court held that cask loading costs are recoverable, other peripheral costs associated with cask loading are also [necessarily] recoverable").

Considering Mr. Brewer's testimony that Plaintiff would have had to incur installation costs for end caps (even assuming such technology was approved for use) if the Government had performed, Plaintiff has not proven that costs similar to those of CILC channeling would not have occurred in a world of DOE performance. Accordingly, Plaintiff has not met its burden to establish damages for the cost of CILC channeling.

Damaged Fuel Bundles. Plaintiff also seeks $1,751,138 in costs associated with loading one damaged fuel assembly for dry storage. The assembly identified by Plaintiff as number "LYN831" was dropped and partially damaged while being moved within the reactor core in September 1993. Entergy Condition Report at -33067, PX 3190. Assembly LYN831 was subsequently moved three times. Specifically, in September 1993, it was moved from the reactor core to the spent fuel pool without incident. *Id.* In 2008, it was moved to another location within the spent fuel pool, also without incident. *Id.* In 2018, the assembly broke into several pieces during an attempt to move it from the pool to dry storage. *Id.* Plaintiff contracted with GE and Holtec to assist in placing the pieces of assembly LYN831 into damaged fuel containers. Swanger, Tr. at 102:16–103:3. Plaintiff argues that if DOE had performed, the assembly would only have been moved twice after it was originally damaged, the second time into a DOE transportation cask. ECF No. 102 at 73 (citing Brewer, Tr. at 1660:13–1661:3). Since the third move would not have occurred had DOE performed, Plaintiff argues that the loading costs resulting from the damage sustained in the third move are attributable to DOE's breach. *Id.*

The Government argues that it is not responsible for the special loading costs of assembly LYN831, as Plaintiff has not proven that the assembly would not have shattered had DOE

performed. ECF No. 104 at 73–74. Mr. Brewer testified that, as soon as assembly LYN831 was damaged in 1993, VYNPS should have put in place special handling procedures to protect the assembly from further damage. Brewer, Tr. at 1573:21–1574:16. Without these procedures in place, and without knowing the failure mechanism, the Government argues there is no reason to conclude the assembly would not have broken apart during loading to a transportation cask just as it broke during loading to a storage cask. ECF No. 104 at 73–74 (citing Brewer, Tr. at 1572:21–25, 1573:5–20, 1575:20–1576:1).

Plaintiff has demonstrated that had DOE performed, all fuel would have been removed from the spent fuel pool by 2016, and the damaged assembly's second move would thus most likely have been into a DOE transportation cask. *See* Brewer, Tr. at 1660:13–1661:3. To establish damages, Plaintiff need not prove with exact certainty the reason for the assembly's initial damage or subsequent failure during loading or prove that the same failure would not have occurred during a hypothetical move in the but-for world. *Dominion Res.*, 84 Fed. Cl. at 270 ("Absolute certainty is not required[.]"). It is undisputed that in the breach world assembly LYN831 was moved twice without incident, notwithstanding the lack of special handling procedures or identification of a failure mechanism addressed by Mr. Brewer. The third move—which took place in 2018, two years after all fuel would have been removed—was only undertaken because of DOE's breach. Plaintiff has sufficiently met its burden, and the special costs associated with loading assembly LYN831 to dry storage are therefore recoverable.

Spent Fuel Pool Filtration and Demineralizer System. Finally, Plaintiff seeks damages for the $334,319 cost of employing a temporary spent fuel pool filtration and demineralizer system. Until shortly after VYNPS ceased operations, Plaintiff used a permanent system to clean the spent fuel pool and protect the surrounding area from radiation contamination. Swanger, Tr. at 96:25–

97:11. The permanent system was labor-intensive and expensive to run; thus, Plaintiff concluded it was not cost effective to continue using the system through 2020, which was when Plaintiff originally expected to complete the transfer of spent fuel from the pool into dry storage. *Id.* at 97:12–25. Instead, in 2015, Plaintiff replaced the permanent system with a new, smaller filtration and demineralizer system to operate inside the spent fuel pool. *Id.* at 97:12–20. According to Mr. Swanger, with an anticipated fuel-out date of 2020, Plaintiff believed the expense of purchasing the temporary system, which was cheaper to operate, was justified in the long-term over continuing to use the permanent system. *Id.* at 97:21–98:7. But if DOE had performed and Plaintiff reasonably knew it would have a fuel-out date of 2016, Mr. Swanger explained that the same cost efficiencies of a temporary system would not have been realized and Plaintiff would not have purchased a replacement for the permanent system. *Id.* at 98:8–14.

Plaintiff contends that the purchase of the temporary system was a reasonable cost-mitigation measure necessitated by DOE's breach. ECF No. 102 at 75. The Government does not dispute that contention. Instead, it raises a causation challenge, arguing that a filtration and demineralizer system would have been necessary for decommissioning regardless of DOE's breach. ECF No. 104 at 79 (citing Brewer, Tr. at 1601:19–1603:13). Mr. Brewer testified that there was "no reason to believe that [VYNPS] would continue to have run all the plant systems to support the vessel segmentation [process]" during decommissioning, and that in his opinion the plant "would have wanted a temporary system or the smaller system the same way they did for the dry storage project." Brewer, Tr. at 1602:12–16; *id.* at 1599:8–23 (explaining need for the filtration and demineralizer system during decommissioning). Indeed, it is common for shutdown plants undergoing decommissioning to disconnect permanent systems and install temporary systems, if possible, as a matter of cost and efficiency. *Id.* at 1600:13–24. While he acknowledges

that Vermont Yankee installed the temporary system in 2015 to support the dry storage project (then-anticipated to conclude in 2020) and used it through 2018 when all SNF was transferred from the pool to the ISFSI, Mr. Brewer notes that the plant continued to use the equipment to support vessel work during decommissioning. *Id.* at 1602:4–12. Mr. Brewer could not identify when the vessel work was completed, but he testified that the work extended beyond the claim period which goes through 2018. *Id.* at 1701:11–14.

The Court finds Mr. Brewer's testimony persuasive. Surely the dry storage project provided the most immediate justification for Plaintiff to install the temporary filtration and demineralizer system in 2015, but the same temporary system could have been used (and has in fact been used) to support decommissioning. Those decommissioning efforts would naturally extend beyond Plaintiff's fuel-out date regardless of DOE's breach. *See* NorthStar DECON – VY SAFSTOR DCE Comparison (July 28, 2016) at -298912, PX 3144 (contemplating "decommissioning, dismantlement and removal of all non-ISFSI structures by 2026"); Decommissioning Cost Analysis for VYNPS (Feb. 2012), Fig. 4.1, 4.2, JX 7 (estimating that large component removal would take 1.5 years to complete). When explaining the rationale of Plaintiff's decision-making, Mr. Swanger focused only on the fuel-out date, testifying that the critical fact was the length of the period of use: a temporary system was justified if SNF remained in the pool until 2020, but it was not justified if SNF remained in the pool until 2016. Swanger, Tr. at 98:1–14. But Mr. Swanger was unable to address the issue of decommissioning and did not know that the temporary system was used during vessel segmentation. *Id.* at 142:5–19. Since utilities commonly install temporary systems to support decommissioning, the Court finds that Mr. Swanger has not reliably modeled what Plaintiff would have done in the but-for world given that his testimony failed to consider an important and common use of the system.

Plaintiff has, accordingly, not met its burden to show entitlement to costs associated with installing the temporary filtration and demineralizer system in 2015.

F. Dry Fuel Storage Project Construction Acceleration Costs Are Recoverable.

Aside from loading costs, Plaintiff is also claiming damages for costs related to the accelerated construction of ISFSI Pad 2. Constructing the second ISFSI pad was necessary to store all the remaining SNF upon retirement of the Vermont Yankee site. *Id.* at 83:24–84:11. Once Plaintiff completed the second ISFSI pad, it planned to reduce the size of the Protected Area to the space immediately surrounding the ISFSIs to reduce security costs. Prefiled Test. of George Thomas at 4–5, JX 9. Under the original project schedule, Plaintiff contracted with Holtec to complete ISFSI Pad 2 by November 15, 2017. Vermont Yankee Dry Fuel Storage Project Execution Plan at -60933, DX 3156. This would allow Plaintiff to complete all cask loading to dry storage by June 2020. Swanger, Tr. at 85:10–17; DX 3156 at -60933. However, based on the amendment of the Holtec HI-STORM COC to allow short-cooled fuel, it became technically feasible to complete the dry storage loading campaign by September 2018. Swanger, Tr. at 87:17–88:2. Advancing the completion date of dry storage loading would significantly reduce staffing and operations costs. PX 3172 at -5940–41. To ensure that the project could be accomplished by the advanced date, Plaintiff made a $1 million payment to Holtec to accelerate the construction of the second ISFSI pad by two and a half months. Swanger, Tr. at 94:11–18. The parties agree that the acceleration of the dry storage project was a reasonable cost-mitigation measure. *See* ECF No. 102 at 64; ECF No. 104 at 80. The dispute centers on whether the acceleration payment was reasonable.

Plaintiff's witnesses testified that accelerating the completion of the second ISFSI pad was done as a risk mitigation measure because the same Holtec crew that was constructing the second

ISFSI pad would also be responsible for work on the Protected Area reduction, and they could not begin on the Protected Area until the pad was complete. Swanger, Tr. at 94:19–95:9, 95:19–23. Plaintiff wanted to use the same Holtec crew for both projects since Plaintiff was familiar with Holtec's work and capability and because of the quality of Holtec's bid. Thomas, Tr. at 497:6–13. Weather was another factor. Considering that winter conditions in Vermont could make construction infeasible, Plaintiff strongly desired to begin construction on the Protected Area reduction before winter set in. *Id.* at 495:5–19; Prefiled Test. of George Thomas at -335347, PX 3171. Because the security barrier was "critical path," for every month the Protected Area construction was delayed, Plaintiff was required to expend an additional $1.2 million in personnel costs. Swanger, Tr. at 94:22–95:15. In short, Plaintiff paid $1 million to Holtec to accelerate the ISFSI project so that it could timely start the Protected Area reduction, saving significant costs and taking advantage of the same crew's experience and expertise. *Id.* at 94:19–96:3; Thomas, Tr. at 497:6–20. Because of the acceleration payment, construction of the second ISFSI pad was completed by September 1, 2017—two and a half months earlier than originally planned, which allowed for the Protected Area reduction to be completed on time. Thomas, Tr. at 495:20–25, 496:25–497:5.

The Government argues it is not liable for the $1 million acceleration payment and $141,259 in associated costs because there was no need to move up the ISFSI pad construction to make sufficient space for casks, since the extra capacity of the second pad would not be needed until January 2018 at the earliest. ECF No. 104 at 80 (citing Brewer, Tr. at 1617:1–18). However, as Mr. Swanger and Mr. George Thomas, a former senior project manager at Vermont Yankee, explained, the acceleration payment was not made only to ensure sufficient dry storage capacity. It was also made to ensure that the experienced Holtec construction crew could be employed for

both pad construction and Protected Area reduction work, the latter of which needed to start before winter and when completed would significantly mitigate costs. Swanger, Tr. at 94:19–96:3; Thomas, Tr. at 471:3–12, 497:6–20.

The Government also argues that the acceleration payment was unreasonable because Plaintiff could have hired a second construction crew to work on the Protected Area reduction concurrently with the second ISFSI pad construction instead of using the same crew for both projects, obviating the need for any acceleration payment. ECF No. 104 at 80–81. But even if Plaintiff could have theoretically hired two crews to work simultaneously, Plaintiff reasonably decided against that path to take advantage of the experience of a single crew. Thomas, Tr. at 497:6–13. It is the Government's burden to affirmatively demonstrate that a mitigation effort was unreasonable. *Energy Nw.*, 641 F.3d at 1307. The Government has provided no evidence rebutting the reasonableness of Plaintiff's decision; rather, it simply points to the availability of other options. That is insufficient.

Finally, the Government argues that Plaintiff has not demonstrated that the acceleration fee actually mitigated costs. ECF No. 104 at 80–81. To the contrary, Mr. Swanger testified that for every month the Protected Area reduction was delayed, Plaintiff incurred an additional $1.2 million in costs. Swanger, Tr. at 95:3–15. Thus, even though Plaintiff spent $1 million for the acceleration fee, it sought to avoid $3 million by completing the construction of the second ISFSI pad and beginning the Protected Area reduction two and a half months earlier than planned. The Government disagrees with this calculus, arguing that cost savings were not realized until all fuel was offloaded in August 2018 and the Protected Area reduction was complete. ECF No. 104 at 81. It contends Plaintiff has not demonstrated that the Protected Area reduction could not have commenced in the spring of 2018 to be timely completed. *Id.* But it did. Mr. Swanger and Mr.

Thomas adequately explained that starting the Protected Area reduction in September 2017 was necessary to ensure that the construction of certain structures could be completed before the ground froze in winter and to ensure Plaintiff's overall project timeline remained intact. Thomas, Tr. at 495:5–19; *see* PX 3171 at -335347 (describing the project as "weather-sensitive" and testifying to the Vermont Public Service Board that "[i]f Entergy VY does not receive authorization by August 31, it may not be able to complete the underground work in 2017, which would extend the installation schedule").

In sum, the acceleration payment was a reasonable cost mitigation measure, as it ensured that Vermont Yankee could achieve the accelerated loading schedule and Protected Area reduction. While there may have been other cost-mitigation options available, the Government has not demonstrated that the option Vermont Yankee chose was unreasonable; therefore, the acceleration payment and associated costs are recoverable.

G. Decommissioning Activity Costs Are Recoverable Only to the Extent They Were Caused by the Government's Breach.

The final category of damages relates to costs that Plaintiff would have incurred during the decommissioning process regardless of DOE's breach, including costs associated with the removal of physical structures and with emergency plan reductions. To the extent Plaintiff has shown that its removal costs would have been less in the absence of the breach, it is entitled to recover the difference in costs. As for the emergency plan work, Plaintiff has not shown that those costs would have been avoided in the but-for world, and thus no recovery is warranted.

1. <u>Costs for the Removal of Some, But Not All, Physical Structures Are Recoverable.</u>

During the claim period, Plaintiff removed and disposed of a structure known as the North Warehouse, a John Deere diesel generator and the warehouse holding it, and a modest amount of OSSI building rubble. Thomas, Tr. at 479:4–16, 502:10–503:15. Plaintiff had to remove these

structures to make space for ISFSI Pad 2 and to facilitate the Protected Area reduction, mitigation activities necessitated by the Government's breach. *Id.* at 479:4–16, 503:5–18; Brewer, Tr. at 1648:18–24, 1676:21–1677:9. The damages sought for removal of the North Warehouse and John Deere generator are $1,808,462. ECF No. 104 at 68; *see* ECF No. 81 ¶¶ 16(h)–(j). Plaintiff also seeks $20,143 in damages for the removal of the OSSI building rubble. ECF No. 81 ¶ 16(l).

Although the parties agree that the removal work was connected to the dry storage project, they also agree that Plaintiff would have removed the structures at issue during decommissioning regardless of the Government's breach. *Id.* at 67–68; ECF No. 105 at 41–42. The question, therefore, is whether Plaintiff has met its burden to show how the removal costs in the breach-world differed from what it would have incurred had DOE performed. *Energy Nw.*, 641 F.3d at 1305. The Court finds that Plaintiff has in part established what its costs would have been in the but-for world.

In a world of full performance, Plaintiff would have removed all the structures at issue during a comprehensive decommissioning effort, rather than in a piecemeal fashion as done here. *See* ECF No. 105 at 41–42 (arguing that piecemeal removal costs are significantly more than if removal was part of an integrated decommissioning plan). Mr. Brewer even admitted that when a plant undertakes decommissioning, it typically hires a decommissioning contractor who plans the timing and sequence of the project to "take advantage of not duplicating efforts." Brewer, Tr. at 1650:3–23. To identify the costs that would have been incurred during decommissioning, Plaintiff offered the 2012 Vermont Yankee Decommissioning Cost Analysis, which estimates various decommissioning costs at the site, including for the removal of structures. JX 7, App. D at 4, 8, 11; Brewer, Tr. at 1654:2–1657:16 (explaining relevant cost breakdown from Decommissioning Cost Analysis). Mr. Brewer testified that decommissioning cost estimates in general are based on

the most accurate information available at the time. Brewer, Tr. at 1649:4–7, 18–21. According to the Decommissioning Cost Estimate, removal of the North Warehouse would cost $205,000. *Id.* at 1657:9–16. Plaintiff has not identified a cost estimate, however, for removing the John Deere generator. Mr. Brewer testified that the generator was considered a yard structure, and the cost of its removal was included within a lump sum line item for removal of yard structures. *Id.* at 1567:17–20, 1568:1–7.

Because Plaintiff is only entitled to recover costs it incurred resulting from the Government's breach, damages should be reduced by the amount Plaintiff would have expended to remove the North Warehouse and the John Deere generator during the unrelated decommissioning process. *See Energy Nw.*, 641 F.3d at 1306–07. Accordingly, Plaintiff is entitled to recover the costs incurred in the breach world ($1,808,462) reduced by the decommissioning estimate for removing the North Warehouse in the non-breach world ($205,000). To take into account the costs of removing the John Deere generator, the Court will apply a reduction equal to a proportion of the North Warehouse removal cost adjusted by size. Since the generator and its warehouse constituted a smaller structure than the North Warehouse, Brewer, Tr. at 1657:22–1658:4, the Court will apply a proportionate reduction of $10,250.[19]

Plaintiff also seeks $20,143 for the costs it incurred to remove the OSSI building rubble. Plaintiff did not, however, provide an estimate of costs for removing the rubble during decommissioning, and the Court can see no way of reasonably estimating such costs based on the evidence. Because Plaintiff has failed to provide the Court with a basis to determine what portion

[19] According to Mr. Brewer's description, the North Warehouse was 120 feet by 50 feet and the John Deere generator was 20 feet by 15 feet. *See* Expert Witness Report of Warren K. Brewer at 7, 13, DX 3267. Being five percent of the area of the North Warehouse, the Court estimates five percent of the warehouse removal cost for the generator removal cost.

of these costs were attributable to the Government's breach and what portion would have been incurred had the Government performed, Plaintiff has not met its burden to recover costs related to the removal of the OSSI building rubble. *See, e.g.*, *Portland Gen.*, 107 Fed. Cl. at 657 ("We have no basis from the record, however, to say what percentage of those costs resulted from the breach and what would have been borne by plaintiffs absent the breach. Thus plaintiffs have not established these costs to a reasonable certainty, and they must be subtracted from plaintiffs' damages.").

2. Emergency Plan Adjustment Costs Were Not Caused by the Government's Breach and Are Not Recoverable.

In August and September 2016, Plaintiff incurred $25,357 to adjust the Vermont Yankee site emergency plan. ECF No. 81 ¶ 16(k); Enercon Invoice for Work Through Aug. 31, 2016, PX 3151; Enercon Invoice for Work Through Sept. 30, 2016, PX 3158. Utilities are required by regulation to have in place an emergency plan in case of a nuclear accident. Swanger, Tr. 96:10–18. Once a plant begins the decommissioning process, it can begin to streamline its emergency plan, which occurs in three steps. Brewer, Tr. at 1607:3–9. A utility can reduce its plan at step one "when the reactor is permanently shut down and all of the fuel is in the spent fuel pool," *id.* at 1607:9–12; at step two, when the spent fuel has cooled in the pool for at least 10 months, *id.* at 1607:14–17; and at step three, when all fuel is in dry storage, *id.* at 1608:5–6. When all fuel is completely removed from a site, there is no longer a need for an emergency plan. *Id.* at 1608:6–8; Swanger, Tr. at 96:19–21.

Here, regardless of DOE's breach, Plaintiff was able to reduce its emergency plan at VYNPS under step one in January 2015, when it offloaded all the SNF assemblies from the reactor core into the spent fuel pool. ECF No. 81 ¶ 4; Brewer, Tr. at 1607:9–13. According to Mr. Brewer, Plaintiff effected that first step-down three weeks after the reactor core was emptied.

Brewer, Tr. at 1609:23–1610:4. In approximately November/December 2015, 10 months after offloading, Plaintiff was able to reduce its emergency plan under step two. *Id.* at 1607:14–18. There is no evidence, however, that it did so at that time.

The next reduction in its emergency plan came in late 2016, only a few months before all fuel would have been removed from the Vermont Yankee site had DOE performed. *Id.* at 1682:5–11. Plaintiff did not present any evidence to describe the nature of the emergency plan reduction work performed in 2016. Mr. Brewer testified that the costs incurred related to a step-two reduction, but also noted that the invoices offered by Plaintiff did not identify the step to which they related. *Id.* at 1610:5–6, 1682:1–12. In its post-trial briefing, Plaintiff claims without citation to any exhibits or testimony that "based on the timing, the available evidence is that the challenged work was in fact 'stage three.'" ECF No. 105 at 43. The Court finds that Plaintiff has not made this showing by preponderant evidence. It is more likely that the 2016 work related to step two based on the fact that it was the second reduction since the Vermont Yankee plant ceased operations. Moreover, it is not a given, as Plaintiff suggests, that Plaintiff would have been planning a step-three reduction in late 2016. Step three can occur when all SNF is moved to the ISFSI. But in late 2016 Plaintiff was just beginning the process of accelerating its dry storage project, and the anticipated acceleration to September 2018 was still two years away. Plaintiff has failed to explain why it would be engaged in such early planning.

Since Plaintiff has not shown that the 2016 emergency plan work related to step three, it has not established its claim for damages. Plaintiff primarily argues that it would not have altered its emergency plan in late 2016 in the non-breach world—just a few months before the need for a plan was obviated—and its costs were therefore caused by the Government's breach. ECF No. 102 at 71 n.14. The Court agrees with the Government that the timing is irrelevant. If Plaintiff's

emergency plan reduction occurred during step two, it would have been required at some point during decommissioning regardless of the Government's breach. Neither the need for a revised emergency plan, nor the fact that Plaintiff chose to incur the real-world costs associated with the plan in late 2016 (even though it was able to implement a step-two reduction a year earlier) were circumstances attributable to DOE's breach. Since Plaintiff has failed to demonstrate that it would not have incurred the costs for the emergency plan alterations but for DOE's breach, it is not entitled to recover such costs.

* * *

Based on the foregoing, Plaintiff is entitled to recover the difference in costs for removal of the North Warehouse and John Deere generator but not for the removal of the OSSI building rubble or the 2016 emergency plan reduction work.

H. The Government Is Not Entitled to a $1.7 Million Per Month Offset.

Finally, the Court must address the Government's offset claim. The Government contends that the Court should "further reduce NSVY's award by . . . $1.7 million per month in cost savings for avoided O&M expenses." ECF No. 104 at 81 (citing Peterson, Tr. at 2077:8–2078:2, 2080:3–8, 2081:10–2082:2). The Government provides no explanation for its claim. However, considering the testimony cited by the Government, the Court infers that the requested offset is based on the assertion of Mr. Thomas, repeated by Mr. Peterson, that Plaintiff saved $1.7 million in O&M costs related to the spent fuel pool each month after all fuel was transferred to dry storage. Peterson, Tr. at 2081:18–2082:2; *see also* Thomas, Tr. at 525:17–22. The offset is presumably based on the Government's theory of a 2020 fuel-out date in the but-for world, meaning it would be entitled to an offset of $1.7 million per month for the months of September through December 2018—the four months during the claim period when all SNF was in dry storage. The Court has

concluded that had DOE performed, all SNF would have been removed from the Vermont Yankee site by the end of 2016. *See supra* § II.B. Thus, any cost savings Plaintiff gained from eliminating the spent fuel pool in 2018 would not have been realized in the but-for world, as the spent fuel pool would have been long empty by then.

CONCLUSION

Based on the foregoing, the Court finds that Plaintiff is entitled to recover damages for the following disputed costs: (1) Wet Pool Storage Costs Between 2017 and August 2018; (2) Resource Code 490 Allocations; (3) Materials Loader Impairment Adjustments; (4) Tax Payments less a reduction of $1,491,134; (5) Damaged Fuel Container Costs; (6) Camera Maintenance and Inspection Costs; (7) Crane Repair and Maintenance Costs; (8) Damaged Fuel Bundle Costs; (9) Dry Fuel Storage Project Construction Acceleration Costs; and (10) Removal of the North Warehouse and John Deere generator less a reduction of $215,250. The Court further finds that Plaintiff failed to meet its burden with respect to all other disputed damages.

The parties shall file a joint notice **by no later than August 5, 2024**, setting forth the total amount that should be awarded on Plaintiff's disputed damages claim consistent with this opinion and the parties' Joint Stipulation (ECF No. 81). The Court will then enter final judgment for the award of both contested and uncontested damages.

SO ORDERED.

Dated: July 29, 2024

/s/ Kathryn C. Davis
KATHRYN C. DAVIS
Judge